



Marketing strategies for ONGC in a deregulated scenario

[Draft Report]

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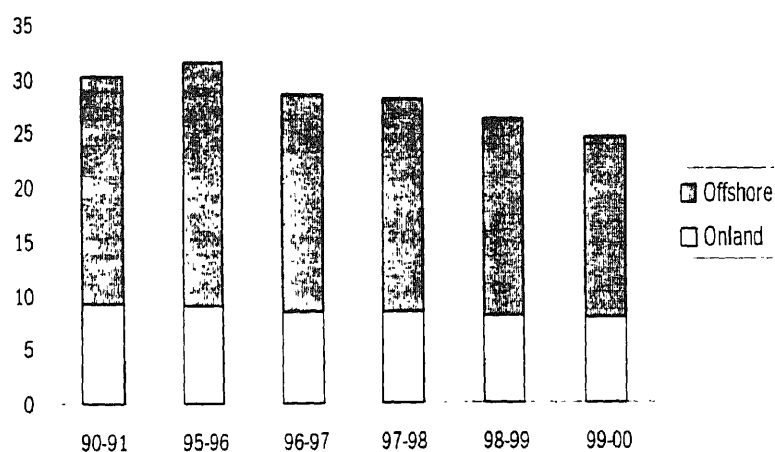
PART-1

Profile of ONGC

The upstream oil sector of India is dominated by the two National Oil Companies – Oil and Natural Gas Corporation Limited and Oil India Limited, with a share of about 88% of country's present oil and gas production. While ONGC produces nearly 77% of indigenous crude oil and 82% of country's gas production, OIL's share of 10% of indigenous oil and 6% of gas production is confined mainly to its areas of operation in Assam, Arunachal Pradesh and Rajasthan. Oil and gas production by OIL in 1999-00 had been 3.3 MMT and 1729 MMCM^a respectively. Whereas oil and gas production by ONGC in the same year had been over 24 MMT and 23252 MMCM respectively.

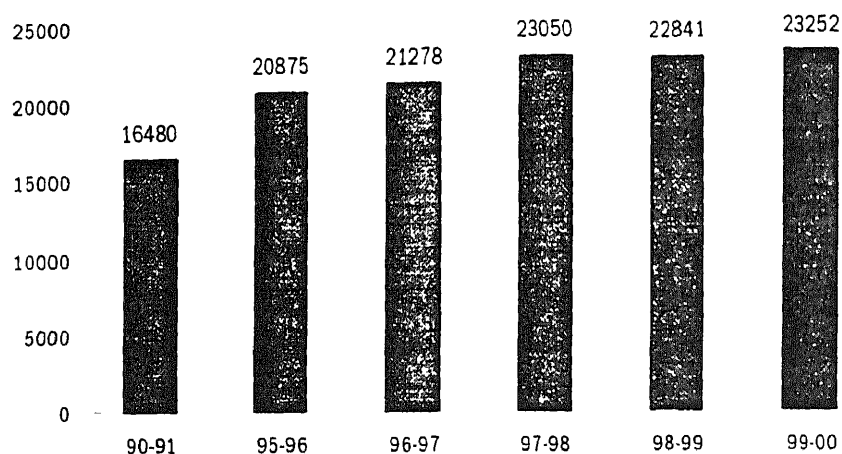
The yearly oil and gas production by ONGC for the last decade is shown in Figure 1.1 and 1.2 respectively.

Figure 1.1 Oil production of ONGC [Production in MMT]



Source. Basic Statistics on Indian Petroleum and Natural Gas, 1999-2000, MoPNG

^a Oil and gas production figures of ONGC and OIL from Basic Statistics on Indian Petroleum and Natural Gas, 1999-2000.

Figure 1.2 Gas production by ONGC [Million Cubic Meters]

Source. Basic Statistics on Indian Petroleum and Natural Gas, 1999-2000.

O and gas production by ONGC shows stagnating trends in the recent years.

Given that India has to import about 70% of its oil requirements and with gas emerging as a major fuel of the future, it is essential that domestic production be increased. ONGC being the major upstream oil company, much of the responsibility of reserve and production accretion falls on ONGC. However, the Xth Plan presents a shortfall in achievements of production targets set by the Planning Commission during the IXth Plan.

Table 1.1 Expected percentage achievement in the IX plan

Activity	Planning Commission Targets	Achievement upto March 2001	Likely Achievement in IX plan	% achievement against PCR
Oil & Condensate production (MMT)	144.894	104.39	129.39	89
Gas Production (BCM)	119.041	92.57	116.57	98

Source. Tenth Plan Sub-Group Report on exploration & production

The Xth Plan targets a domestic oil production of about 32 MMT by 2006/7, whereas the demand is expected to reach about 214 MMT. This gap of 85% is to be bridged by imports. ONGC targets an oil production of about 25 MMT by 2006/7. Any shortfall from domestic production targets will further increase the import dependence.

The oil production projections of ONGC also show stagnating and even declining trends till 2006/7 as shown in Table 1.2 below. However, in light of huge investment plans made by ONGC for E&P activities and the Bombay High

Redevelopment Plan, it can be expected to make substantial improvements in current oil and gas production levels

Gas production projections by ONGC are shown in table 1.2 and also presents stagnating trends.

Table 1.2 Oil and gas production projections of ONGC

	2002-03	2003-04	2004-05	2005-06	2006-07
Oil (MMT)	25.897	25.995	26.382	26.189	25.562
Gas (MMCMD) ^a	50.48	48.88	46.05	46.51	47.04

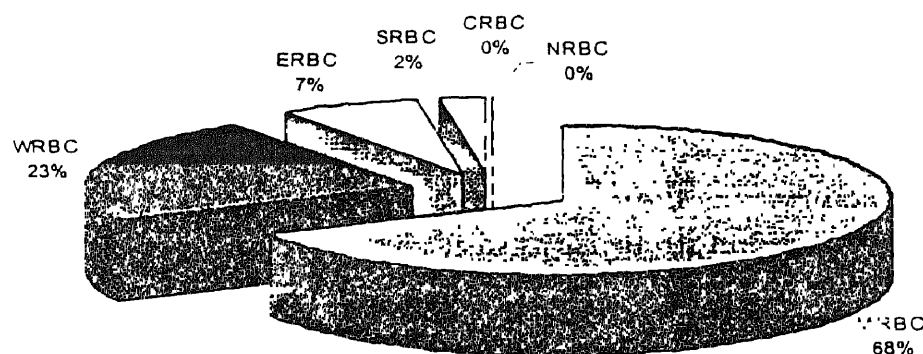
Source. ONGC

ONGC's exploration and production activities are spread over the following regions:

1. Mumbai – Bombay High fields
2. Western region – the Gujarat and Cambay basin
3. Eastern region – Assam and Tripura fields
4. Southern region – Krishna Godavari and Cauvery basin
5. Central region – with headquarters at Kolkata

The maximum production is centred in the Bombay High region and accounts for around 68% of the total ONGC crude production.

Figure 1.3 Share of business centres



Crude oil production by ONGC from all regions is sweet crude with sulphur content being less than 0.5%. The Xth Plan projects that the demand for sweet crude in India will rise from about 28 MMT in 2002/3 to about 39 MMT in 2006/7. As such ONGC is not expected to face any demand crunch for its crude.

^a Does not include production from joint venture fields

However, uncertainty remains as to how to market this crude so as to obtain the best prices. The same applies to natural gas as demand far exceeds domestic supply.

However in view of emerging surplus refining capacity in India, and surplus of naphtha in the country, offtake of value added products of ONGC may be uncertain. Bulk of the value added produce of ONGC includes naphtha and LPG. The Xth Plan projects a negative growth rate of naphtha demand by 3.5% till 2006/7, but expects the demand for LPG to grow substantially at the rate of 8.2%. In line with these projections, ONGC projects a decline in naphtha production from 1.5 MMT in 2002/3 to 1.16 MMT in 2006/7. However it also projects a fall in its LPG production from 1 MMT to 0.87 MMT in the same period. The year-wise naphtha and LPG production projections by ONGC is shown in Table 1.3 below.

Table 1.3 Production of Naphtha and LPG by ONGC (MMT)

	2002-03	2003-04	2004-05	2005-06	2006-07
Naphtha	1.482	1.290	1.189	1.171	1.160
LPG	1.013	1.002	0.936	0.899	0.873

Till now ONGC had been selling crude oil to refineries as directed by the Oil Coordination Committee. Sales of natural gas is through GAIL and allocations are made by the Government. For consumers taking gas directly from ONGC, the allocations are decided by the Gas Linkage Committee. Sales of LPG is also guided by OCC through the OMCs – IOC, HPCL and BPCL. However, naphtha is a decontrolled product and ONGC is free to market its naphtha. Bulk of the naphtha is sold through the OMCs while ONGC undertakes some direct marketing also. However with complete deregulation of the Indian oil industry, given that marketing is not the core area of ONGC, the organisation has to gear up to the competition and strategise its sales so as to obtain best deal for all its products.

Given this backdrop, this study focuses on developing a strategy for marketing crude oil, natural gas and value added products, premised on a changed scenario that will prevail in the post deregulation period.

Part 1 of the report addresses marketing issues related to crude oil. In Chapter 2, the global oil scenario has been evaluated to establish the reserves, major producers and consumers of crude oil, and the likely scenario that would prevail in the future. Chapter 3 presents a brief on oil prices is also presented, followed by the likely demand supply scenario for crude oil envisaged for India in the next five years. Chapter 4 details the international classification of crude oil and in this context the crudes that ONGC's oil could be benchmarked to are enumerated, along with the international markets for these benchmarks.

Chapter 5 outlines the current demand for crude by refineries, focusing on the demand for sweet crude, which ONGC could meet. Chapter 6 examines the supply infrastructure for the refineries including details such as ownership, to highlight the current linkages in place. Chapter 7 provides the policy context within which crude sales are currently made in India.

In Chapter 8, a brief outline provided on the methodology adopted for evaluating marketing options for ONGC's crude followed by details for Bombay High, North and South Gujarat, North East crude, JV crude respectively in Chapters 9, 10, 11 and 12.

Part 2 of the report is focussed on Natural gas. Chapter 13 begins with an analysis of the demand-supply situation for gas, projections of demand linked to the imputed value of gas, the likely LNG projects that would come up in the next five years and the impact that could have on pricing of gas. Finally the avenues open to ONGC for marketing its gas are considered and evaluated.

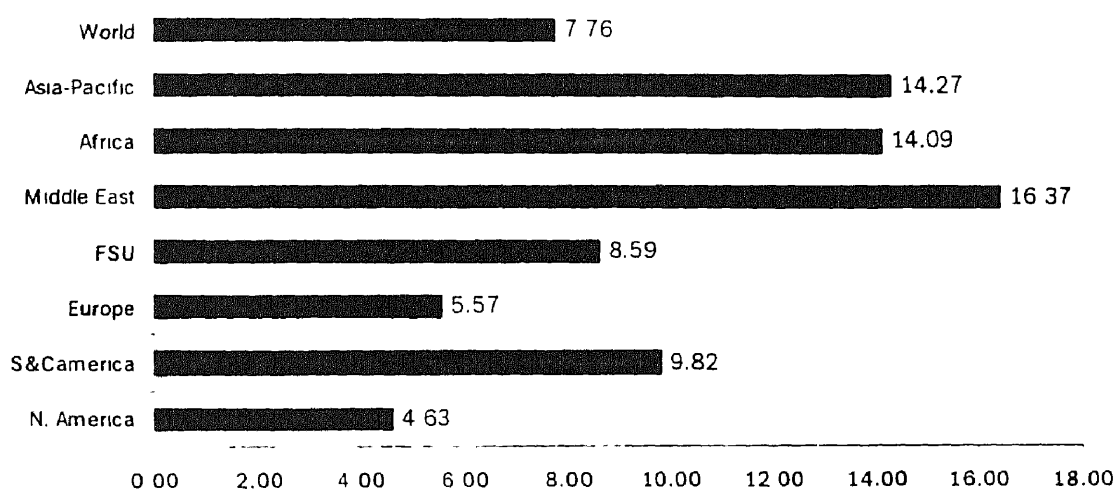
Part 3 of the report begins with Chapter 14 examining the case for naphtha marketing and Chapter 15 deals with LPG marketing.

Primary energy consumption

Energy is key driver of economic growth. The industrially developed countries are heavily dependent on energy for economic prosperity. The largest economies are the largest consumers of energy in the world. Historically, North America has been the single largest consumer of primary energy in the world followed by Europe and Asia-Pacific.

The following chart shows the rate of growth in energy consumption of major regions in the world over the period 1990-2000.

Figure 2.1 Rate of growth in energy consumption (%) - 1990 - 2000



Source. BP Amoco Alive 2001

The developed regions like N.America and Europe have shown a slow rate of growth over the period while the developing regions like South and Central America, Africa, Middle East and Asia-Pacific have shown a high energy consumption growth rate. This has resulted in a shift in the weight of the regions in total energy consumption, as shown in the table below.

Table 2.1 Share of regions in total energy consumption (%)

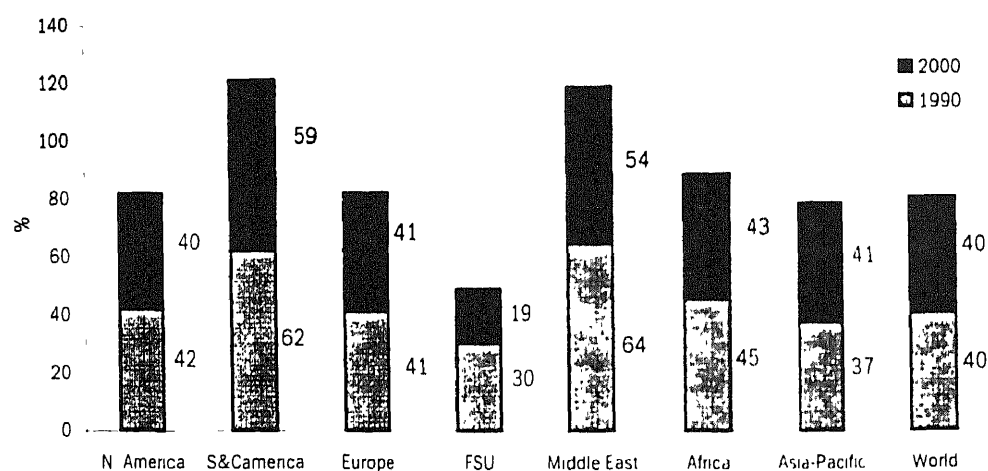
Region	1990	2000
N. America	28.3	30.1
S&C America	3.4	4.2
Europe	22.1	20.8
FSU	17.7	10.5
Middle East	3.3	4.4
Africa	2.7	3.1
Asia-Pacific	22.5	26.9

North America has maintained its overall leadership in energy consumption.

Importance of oil

The share of oil in primary energy consumption has remained unchanged at 40% from 1990 to 2000. Almost all the regions have experienced a decline in the share of oil with the sole exception of Asia-Pacific. The largest decline has occurred in Former Soviet Union (FSU) where the share of oil declined from 30% to 19% followed by Middle East where the share declined from 64% to 54%. Asia-Pacific, on the other hand, has seen an increase in the share of oil from 37% to 41%, as shown in the figure 2.2.

Figure 2.2 Share of oil in meeting energy requirement (%)



Source: BP Amoco Alive 2001

Global oil production and consumption

Current scenario

Total proven reserves of world oil is 1046.4 thousand million barrels. Of this the Middle East Gulf countries have the largest share of about 65%. Accordingly,

this region is an important producer and supplier of oil having the largest share of 31% in total oil production of 74.15 million barrels per day. Region-wise reserves and production of oil are listed in Annexure 2.1. At the current production levels these reserves are expected to last for 83 years. Saudi Arabia is the single largest oil producing country in the world, whereas USA is the largest consumer accounting for a quarter of world's oil consumption in 2000. The major producers and consumers are listed in Annexure 2.2.

Future outlook

According to World Energy Outlook (WEO) 2001, oil production is projected to increase to 87.9 million bbl per day by 2005 and to 97.4 million bbl per day by 2010. This implies an annual growth rate of 4% from 2000 to 2005. Likewise, consumption is projected to grow from 84.9 million barrels per day by 2005 to 94.9 million barrels per day by 2010. The detailed projections are shown in Annexure 2.3.

Oil trade

Current scenario

Crude oil is the world's most actively traded physical commodity; the largest markets being in London (International Petroleum Exchange), New York (New York Mercantile Exchange) and Singapore (Singapore Mercantile Exchange). The table below shows the trade movements in the year 2000.

Table 2.2 Oil trade movements, 2000

From	To													Total
	USA	Canada	Mexico	S & C America	Western Europe	Central Europe	Africa	Australia	China	Japan	Other Asia Pacific	Rest of World	Unidentified	
USA	-	101	267	163	211	-	6	8	4	35	78	17	-	890
Canada	1686	-	-	4	12	-	-	-	-	-	-	-	-	1703
Mexico	1360	26	-	169	202	-	4	-	-	42	6	4	-	1814
S&C America	2576	126	21	-	250	4	12	4	8	4	73	-	-	3079
Western Europe	888	568	4	29	-	197	175	2	52	6	141	48	-	2110
FSU	66	-	-	162	2511	806	10	-	96	6	150	47	417	4273
Central Europe	-	-	-	-	67	-	-	-	-	-	2	52	-	121
Middle East	2496	104	19	427	3666	198	705	203	770	4189	6115	52	-	18944
North Africa	229	76	54	26	2050	60	71	-	4	12	85	64	-	2732
West Africa	1398	22	-	126	553	2	44	-	268	16	863	-	-	3293
East & South Africa	-	-	-	-	4	-	-	-	66	26	30	-	-	126
Australia	48	-	-	-	-	-	-	-	30	95	275	-	-	449
China	44	-	-	4	2	-	4	8	-	123	164	2	-	352
Japan	13	-	-	-	2	-	-	8	13	-	46	-	-	81
Other Asia Pacific	182	2	-	2	27	-	-	302	464	768	202	17	-	1966
Unidentified	105	44	-	-	509	-	-	47	8	6	14	-	-	733
Total Imports	11092	1070	365	1112	10066	1268	1032	583	1783	5329	8246	303	417	42666

Source: BP Amoco Alive, 2001

Of total oil exports in the world, the largest share (45%) was from the Middle East region followed by Africa (share of 14%). Major oil reserves in the world are

in the Middle East countries whereas consumption within these countries is comparatively much less resulting in availability of huge crude oil surplus in this region. Major consumption centres of oil from the Middle East Gulf are in USA followed by Asia and Europe. USA is the largest net importer of oil, and Saudi Arabia the biggest exporter. Country-wise oil exports and imports from 1995-2000 have been illustrated in Annexure 2.4.

The major sweet crude producing regions are Asia-Pacific, Africa and Europe whereas Middle East largely produces sour crude. The African crude is primarily consumed in North America and Europe while the Asia-Pacific crude is primarily consumed within Asia-Pacific with Japan and China being the major consuming countries. The details of sweet crude demand-supply and markets are discussed in detail in Chapter 4.

Future outlook

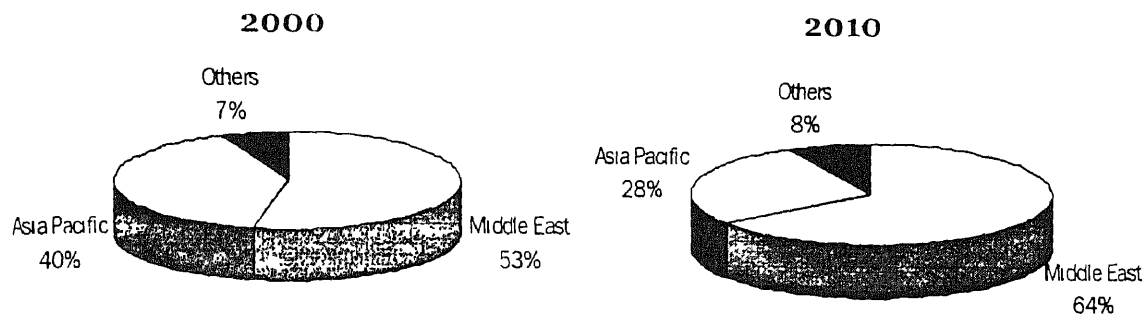
From Annexure 2.3, it can be assessed that Middle East countries will have an increasing oil surplus and hence will continue to contribute significantly to world exports. Also the Asia-Pacific region shows an increasing consumption-production gap or consumption deficit. Hence this region can be expected to command the largest import flows. Table 2.3 below shows the projected oil deficit/surplus.

Table 2.3 Net oil deficit/surplus (mb/d)

	Deficit/Surplus (million bbl/day)			
	2005	2010	2015	2020
North America	-9.5	-11.5	-13.1	-15
Middle East	22.6	26	31.2	36.6
South and Central America	3.1	3	2.8	3.1
Europe	-8.6	-9.1	-9.7	-10
Asia-Pacific	-15.8	-19.8	-24.7	-29.6
Former Soviet Union	4.7	6.3	6.7	7
Africa	6.5	7.6	9.1	10.8
World	3	2.5	2.3	2.9

Trade in Asia-Pacific

According to FACTS, stagnated oil production in Asia and increasing oil use is reflected in growing imports. According to FACTS, about 60% of crude oil imports by Asia-Pacific countries in 2000 came from sources outside the region and this is expected to rise to 72% in 2010. Middle East is the main exporter to Asia-Pacific countries. The share of the region's crude imports from Middle East is expected to increase from 53% in 2000 to 65% in 2010.

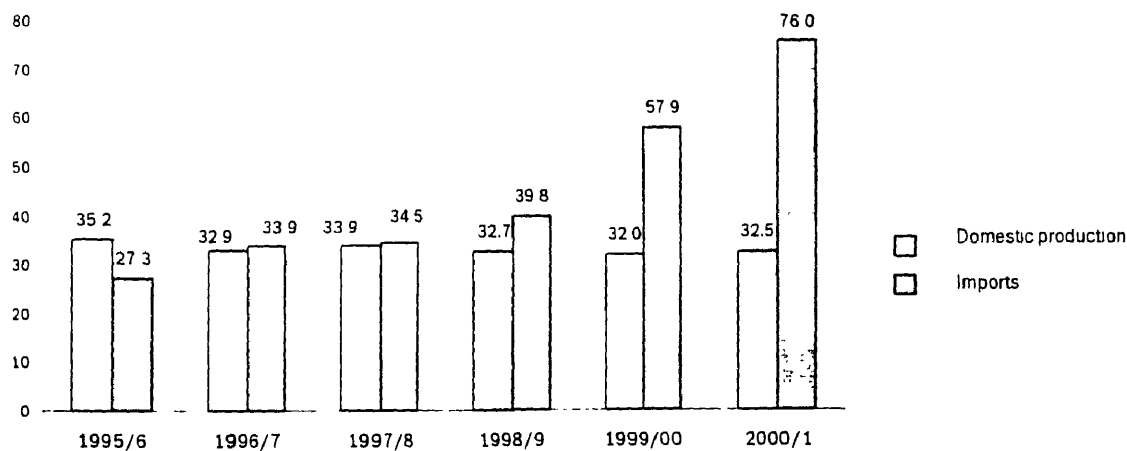
Figure 2.3 Projected crude oil import pattern in Asia-Pacific

Source. FACTS Energy Advisory Report No.255, June 2001

The major crude exporters in the region are Indonesia, Malaysia and Vietnam. Vietnam exports over 99% of its crude oil. Though Australia shows a negative exportable surplus, it trades certain crude oils like the Thvenard Island and Jabiru. China used to be the second largest crude exporter in the region during the mid 1980's. However today it is a huge importer of crude oil and at present imports about 1.4 million barrels/day (FACTS Inc, Energy Advisory Report No 255, June 2001).

Trade in India

India is largely dependent on imported crude oils and imports show an increasing trend over the years as is evident from Figure 2.4.

Figure 2.4 Trend in domestic crude oil production and imports (MMT)

Source: CMIE

The Tenth Plan projects oil imports by India to increase to about 147 MMTPA by 2006/7. Like most of the oil importing countries in the world, India sources most of its crude oil from the Middle East countries followed by African countries. Crude oil imports by India and requirement of Indian refineries are discussed in details in Chapter 5.

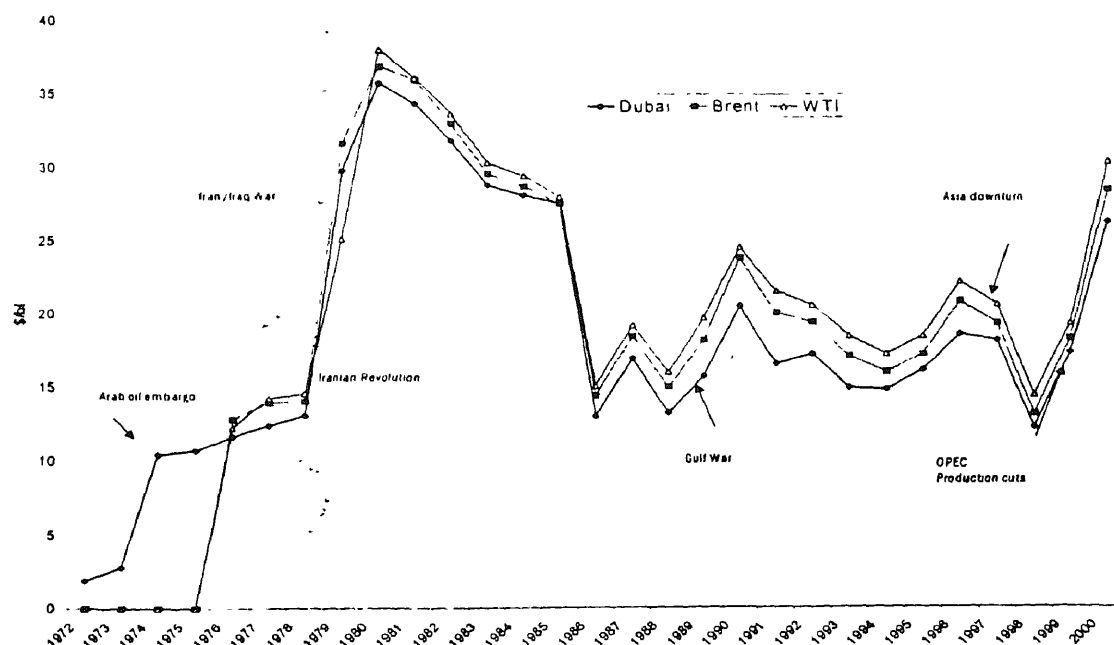
International oil prices

Akin to other commodities the price of crude oil is closely linked to demand and supply situation. Oil prices are highly volatile, as demand and supply of oil are vulnerable to various factors – political forces, unforeseen events like wars or natural calamities, climate or manipulations by large oil producers.

OPEC countries command about 44% of world oil production. Moreover, over the years OPEC has become a cohesive group of producing countries whose commercial interests anciently do not conflict and therefore OPEC has been recently able to regulate the production of oil successfully. As price of any commodity is fundamentally governed by the forces of demand and supply, the cap on oil supply has triggered an upward pressure on the price of this commodity. Therefore the oil prices at present are not strictly governed by market forces.

Figure 3.1 below illustrates how world events have affected oil prices in the over the years.

Figure 3.1 Crude oil prices (\$/bbl)



Recent price trends

In 1997, the financial crisis and economic slowdown in Asia led to a slackening of oil demand that sent oil prices crashing to \$ 10/bbl in 1998-99. Consequently from March 1999 onwards OPEC decided to cut production and in effect removed about 5 million bbl/day from the market. This accompanied with falling inventories, led to price recovery of more than \$ 30/bbl. OPEC once again increased production in March 2000, resulting in lowering prices to \$ 21/bbl.

During the March 2000 meetings, OPEC adopted a target range for the OPEC basket price of oil between \$22 and \$28 per barrel according to the formula. Prices above the range, sustained for 20 trading days, would result in increases in production of 500,000 b/d. Prices below the target range for 10 trading days would result in cuts in production of 500,000 b/d.

However the oil prices had reached a high level of \$33 a barrel last year, but have been softening this year. So much so that OPEC decided in July to cut production by a million barrels a day with effect from September 1, 2001. The EIA had also reported that the market would be more or less stable for the rest of the year. The attacks on the US on September 11 took place in this background. The attacks on the US on September 11 took place in this background. Immediately the oil price went up by \$2 /bbl. This was caused by traders anticipating an immediate retaliation by the US. However, the retaliation did not come and the price started moving down within two days. OPEC has decided to maintain the production level. On October 5, the price of the OPEC basket of crude oils stayed below \$22 a barrel for 10 consecutive days. Normally, this would bring an automatic cut of 500,000 barrels a day in OPEC production. There has been no move so far toward production cuts.

Presently, the prices are in the range of \$18 - \$20 per barrel and OPEC has been justifying the production cuts to bring the prices in line with its target band.

Oil markets

Oil prices are very sensitive and hence oil trading carries with it a high degree of risk. The decade of 1970 was an important phase in the development of international oil market. This decade was marked by the de-integration of the oil industry because of the nationalisation of the assets of the big multinationals in the OPEC and some other third world oil producing countries. As a result, the major companies lost privileged access to the equity oil for their refineries. A two-part structure was born in which the producing countries became seller of

crude oil rather than the passive tax recipient and the oil majors became buyers of crude oil rather than the tax payers.

Emergence of trading instruments

With the emergence of bi-polar market for oil in which OPEC and non-OPEC markets were often pulling the prices in different directions, the price risk rose. The crude oil purchased in OPEC region on OPEC fob often proved to be too expensive compared to equivalent non-OPEC crude when it reached the final destination. Occasional changes in the administered price highlighted the need to hedge the sales as well as purchases. Slowly, the spot market started to grow at an accelerated pace, largely because of the trading between the holders of the term contracts who were then able to match and balance their crude oil requirement. Instruments new to the oil market like forwards, futures and swap deals followed this.

The two major trading exchanges are the NYMEX (New York Mercantile Exchange) and the IPE London (International Petroleum Exchange). These markets use a variety of information from various sources to fix the crude oil prices in the forwards and futures markets which forms the base for prices in the spot markets.

Marker crude oils

Brent as world marker

As there are a large number of crude oils with varying properties, buyers and sellers find it convenient to refer to a few crudes as benchmark. Prices of other crudes are accordingly indexed to these marker crudes at a discount and premium. The major benchmark crudes are Brent from UK, West Texas Intermediate (WTI) from USA, Dubai from Dubai and Tapis from Malaysia. Spot trade is also carried out as differentials against official selling prices (OSPs) as quoted by some countries in the Middle East and Far East.

Brent has generally been accepted as the world's benchmark crude although sales volume of this crude maybe less than some of the other crudes particularly those from Saudi Arabia. According to the International Petroleum Exchange (IPE), Brent is used to benchmark two-thirds of total crude oil traded in the world. Most of the trade in North Sea, West Africa and Mediterranean regions is carried out against dated Brent. The spot prices of Brent have been presented in Figure.

US marker crude

West Texas Intermediate (WTI) is the benchmark crude for sales of crude oil in the US. The prices of crude oil sold in the US are in relation to prices of WTI. However, though majority of the exports from West Africa goes to the USA, trade against WTI (from Africa) is not large and much of the trade with WTI as marker takes place in the US Gulf Coast (USGC). For example, price of Qua Iboe from Nigeria landing at USGC is differenced against WTI.

Middle East Gulf marker crude

Middle East exports approximately 45% crude oil to the various countries in the world. The economy in these countries is dominated by the oil sector. Traditionally the entire oil sector is controlled by the national oil companies who are working directly under the regimes of the ruling monarchy. These companies have been marketing their crude oil based on their official selling price (OSP) without negotiations.

The important features of this pricing policy are as follows:

1. Crude oil is normally marketed on an annual basis through term contract at the official selling prices.
2. The OSPs relate to the daily market price of some other marker crude oil traded in the market.
3. The OSPs contain the following elements:
 - (i) price linkage
 - (ii) price out period
 - (iii) publication – e.g. Platt crude oil market wire etc.
 - (iv) premium/discount (this indicate the quality difference of the crude oil vis-à-vis marker crude oil and the demand-supply situation of the crude oil)
4. Since these countries market their crudes to different regions of the world therefore they have different official selling price for different markets.
5. The OSPs of Saudi Arabia, Kuwait and Iraq are evaluated under three names, namely US Market, European Market and East of Suez Market.
6. The marker crudes for these markets are as follows:
 - (i) US Market – WTI
 - (ii) European Market – Brent blend
 - (iii) East of Suez Market – average of Oman and Dubai Crude oils
7. The National Oil Company declares the official selling price every month (i.e. the applicable premium/discount) for a particular month of loading.

The prices applicable to the east of Suez market

Saudi Arabia, Kuwait and Iran use the monthly average of Oman and Dubai as published in Platts crude oil market wire for the month of loading plus/minus the premium/discount.

Iraq uses the average of Oman and Dubai crude oil published in Platt crude oil market wire for the ten quotation starting from the date of bill of lading. The premium/discount is revised every month.

UAE announces a fixed price for crude oils marketed by it. However, the price arrived at is based on the price of Dubai crude oil with suitable adjustment for quality, market condition etc. The price is announced after completion of the month in the first week of the following month.

This methodology of UAE for declaring OSP is also followed by Oman and Qatar.

Trade from the Mideast Gulf is also carried out against OPEC Basket. OPEC is an organisation consisting of all major oil producing countries. These countries have their own benchmark crude called OPEC basket. OPEC basket price is the average price of the following seven crude oils:

- (1) Saudi Arabia's Arab Light
- (2) UAE's Dubai
- (3) Nigeria's Bonny Light
- (4) Algeria's Saharan Blend
- (5) Indonesia's Minas
- (6) Venezuela's Tia Juana Light
- (7) Mexico's Isthmus

OPEC members produce six of these crudes while Mexico who is not a member of the OPEC cartel produces Isthmus. The following table shows the pricing formulae for various crudes for various markets.

Table 3.1 Pricing formulae for Asia market

Grade of crude - API	Point of sale	Price formula	Adjustment Factor 00/9
For Asian Market			
Saudi Arabia			
Arabian Light - 33	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	0.1
Arabian Heavy - 27	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-1.5
Iran			
Iranian Light - 33	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	0
Iranian Heavy- 30	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-0.65
Kuwait			
Kuwait - 31	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-0.95

Grade of crude - API	Point of sale	Price formula	Adjustment Factor 00/9
Neutral Zone			
Khafji - 28	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-1.5
Qatar			
Dukhan - 41	Fob	(Oman MPM) +- (Adjustment factor)	0.75
Manne - 36	Fob	(Oman MPM) +- (Adjustment factor)	0.27
Iraq			
Basrah - 34	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-1.1
Yemen			
Marb - 48	Fob	(Dated Brent) +- (Adjustment factor)	-0.5
Masila - 30.5	Fob	(Dated Brent) +- (Adjustment factor)	-1.2
Mexico			
Isthmus - 33	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	0.1
Maya - 32	Fob	(Dubai + Oman)/2 +- (Adjustment factor)	-2.65

Table 3.2 Pricing formulae for US market

Grade of crude - API	Point of sale	Price formula	Adjustment Fac. 00/9
For US Market			
Saudi Arabia			
Arabian Light - 33	Fob	(WTI) +- (Adjustment factor) - (Freight discount)	-4.65
Arabian Heavy - 27	Fob	(WTI) +- (Adjustment factor) - (Freight discount)	-6.35
Kuwait			
Kuwait - 32	US Gulf	(WTI) +- (Adjustment factor)	-4.6
Iraq			
Basrah - 34	Fob	(WTI) +- (Adjustment factor)	-6.7
Kirkuk - 37	Ceyhan	(WTI) +- (Adjustment factor)	-5.5
Nigeria			
Bonny Light - 36	Fob	(Dated Brent) +- (Adjustment factor)	0.2
Forcados - 29	Fob	(Dated Brent) +- (Adjustment factor)	-0.4
Brass River - 42	Fob	(Dated Brent) +- (Adjustment factor)	0.15
Mexico			
Isthmus - 33	Fob	0.4 x (WTS + LLS) + 0.2 x (Dated Brent) +- (Adjust. Factor)	-1.5
Maya - 32	Fob	0.4 x (WTS + 3% Fuel Oil) + 0.1 x (LLS + Dated Brent) +- (Adjust. Factor)	-2.55
Olmecca - 39	Fob	(WTS + LLS + Dated Brent)/3 +- (Adjustment factor)	0.05
Colombia			
Cano Limon - 30	Fob	(WTI) +- (Adjustment factor)	-4.52
Venezuela			
Fumal - 30	Fob	(WTI) +- (Adjustment factor)	-4.72

Table 3.3 Pricing formulae for West European market

Grade of crude – API	Point of sale	Price formula	Adjustment Factor 00/9
For West European Market			
Saudi Arabia			
Arabian Light – 33	Fob	(BWAVE) +- (Adjustment factor) - (Freight discount)	-3.95
Arabian Heavy – 27	Fob	(BWAVE) +- (Adjustment factor) - (Freight discount)	-6.2
Kuwait			
Kuwait – 31	Fob	(BWAVE) +- (Adjustment factor)	-5.1
Iran			
Iranian Light – 33	Rotterdam	(Dated Brent) +- (Adjustment factor)	-0.84
Iranian Heavy – 30	Rotterdam	(Dated Brent) +- (Adjustment factor)	-1.34
Iraq			
Kirkuk – 37	Ceyhan	(Dated Brent) +- (Adjustment factor)	-3.5
Yemen			
Manb – 48	Fob	(Dated Brent) +- (Adjustment factor)	-0.5
Masila – 30.5	Fob	(Dated Brent) +- (Adjustment factor)	-1.2
Nigeria			
Bonny Light – 36	Fob	(Dated Brent) +- (Adjustment factor)	0.02
Forcados – 29	Fob	(Dated Brent) +- (Adjustment factor)	-0.4
Brass River – 42	Fob	(Dated Brent) +- (Adjustment factor)	0.15
Libya			
Es Sider – 37	Fob	(Dated Brent) +- (Adjustment factor)	-0.8
Zueitina – 42	Fob	(Dated Brent) +- (Adjustment factor)	-0.6
Syna			
Syna Light – 37	Fob	(Dated Brent) +- (Adjustment factor)	-2.5
Souedieh – 24	Fob	(Dated Brent) +- (Adjustment factor)	-6
Egypt			
Suez Blend – 32	Fob	(Dated Brent) +- (Adjustment factor)	-4
Belayim Blend – 26	Fob	(Dated Brent) +- (Adjustment factor)	-5.3
Mexico			
Isthmus – 33	Fob	$0.887 \times (\text{Dated Brent}) + 0.113 \times (3.5\% \text{ Fuel Oil}) - 0.16 \times (1\% \text{ F.O.} - 3.5\% \text{ F.O.}) \pm (\text{Adjust. Factor})$	-0.11
Maya – 32	Fob	$0.527 \times (\text{Dated Brent}) + 0.467 \times (3.5\% \text{ Fuel Oil}) - 0.25 \times (1\% \text{ F.O.} - 3.5\% \text{ F.O.}) \pm (\text{Adjust. Factor})$	-1.1

Source: IEEJ, July 2001

WTI: West Texas Intermediate, LLS: Louisiana Light Sweet; WTS: West Texas Sour; Oman MPM: Posted price of Oman crude; BWAVE: IPE Brent Weighted Average.

Note: "The Adjustment Factor" in the price formula for Saudi Arabian crude directed to the US/European market include the "Freight discount factor"

Price forecasts

Crude price forecast is an extremely difficult exercise as the prices are governed by a number of unreported events and other factors like demand and supply etc. Nevertheless several agencies are engaged in price forecasting exercises and some forecasts are presented as follows.

The Madison Energy Advisors' oil price forecasts, as quoted in the Oil and Gas Journal (Feb 12, 2001), suggested a consensus that WTI prices will retreat somewhat from the 2000 levels.

Table 3.4 Madison Energy Advisors forecasts (\$/bbl)

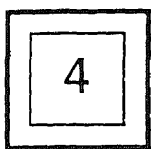
	Houston Energy Banks*	Active middle market*
2001	24.02	26.51
2002	20.87	24.78
2003	20.73	23.95
2004	21.10	24.27
2005	21.48	24.77

*: The forecasts are based on a poll of Houston Energy banks and by companies active in the middle range of acquiring and divesting producing oil and gas properties.

The UK based Centre for Global Energy Studies forecasted a price range of \$ 19- \$ 35/bbl in the first quarter of 2002. While the higher end of the range coincides with a scenario of the cuts announced in March and less Iraqi oil entering the market, there is a feeling in the market that production cuts won't be observed by the members and non-members in their entirety. The lower end of the forecast is based on low demand scenario accompanied by no cuts by OPEC.

The Energy Information Administration (US Department of Energy) indicate that the average world oil price will increase from \$17.35 per barrel in 1999 (1999 dollars), to \$27.60 per barrel in 2000, falling to about \$20.50 per barrel by 2003. In 2020, the price reaches \$22.41 per barrel. The firmness of prices over the next several years in this study by EIA is attributed to production cutbacks by OPEC and several non-OPEC nations, a lag in the response of non-OPEC producers to price increases, and renewed demand growth in Asia.

The price that ONGC could get in international markets would be closely linked to the international crudes it is benchmarked to, the demand for ONGC crude as also the markets for which ONGC would compete.



International markets for ONGC crudes

Oil producing regions

Crude oil comes in different varieties and qualities depending mainly on its specific gravity and sulphur content which in turn depend on the region from where the oil has been explored and pumped. Sweet crude can be defined as oil having sulphur content less than 0.5%, whereas crude containing more than 0.5% sulphur is categorised as sour. World Energy Council classifies oil as heavy if its API gravity is $<22.3^{\circ}$. Oil with $\text{API} < 10^{\circ}$ are often categorised as bitumen or extra-heavy oil.

Basic properties of major crude oils in the world is discussed below. The world can be divided into 5 major oil producing regions – The Middle East Gulf, Africa, North Sea Europe, United States and Canada, Former Soviet Union and the Far East.

Middle East Gulf

The Gulf region is the major oil producing and exporting region in the world. The Middle East contributes to about 45% of world oil exports. Crude oils from this part of the world have relatively high sulphur content but they are mostly light. Marib Light from Yemen is by far the best quality crude in this region. It is not only a light crude but sweeter than most crudes from this part of the world. The detailed list outlining the characteristics of all the crude from this region are presented in Annexure 4.1.

Africa

Most of the production from the African continent comes from Nigeria followed by Libya, Algeria, Egypt and Angola. West African grades are typically sweet, with medium to light gravity. Major crudes from Africa are listed in the Annexure 4.2

North Sea

Norway and United Kingdom hold the majority of the North Sea's oil reserves. The most important crude from this region is the Brent blend. It is a mixture of oil streams collected from two distinct pipeline systems – the Brent and the

Ninian systems. Brent blend can be characterised as light, sweet crude oil. Horsnell and Mabro provides that, during 1980-1992, the gravity of its constituent parts varied from 30-31° API (the Hutton and Osprey fields) to 39-40° (the Brent, Alwyn North, Don and Staffa fields). Sulphur content varied from 0.2% by volume for the Brent and Alwyn North fields up to 1% for the Tern field. The incremental developments of the Brent system produced oil that was much heavier and had higher sulphur content than the existing fields. By contrast, the quality of the Ninian stream improved significantly over time, became lighter than the Brent stream in 1988. As per reference texts, the gravity of Brent blend is normally taken to be around 38° API.

API and sulphur of important crudes from this region is provided in Annexure 4.3.

United States of America and Canada

The West Texas Intermediate (WTI) and Alaskan North Slope (ANS) are the most important crude oils from the USA. WTI is a light sweet crude whereas ANS is a medium heavy, sour oil. Canada has the largest heavy oil resource in the world followed by Venezuela. Oil from Canada is also very sour. Canada's heavy oil and bitumen is situated in the Athabasca, Wabasca, Peace River and Cold Lake areas of Alberta and in the Lloydminster area of Saskatchewan. Venezuela has extra-heavy oil in the 400 mile long Orinoco belt, in the east of the country. Alaska and Mexico also have large reserves of heavy oil. Major oils from America and Canada are listed in Annexure 4.4.

Former Soviet Union

Crude oils from the Soviet Union (former) range from being light-sweet in one region to heavy-sour in some other region and cannot be typecast into any single category. The API and sulphur content of some crude oils from Russia have been illustrated in Annexure 4.5.

Asia and the Far East

The Far Eastern crude oil is comprised primarily of Indonesian and Malaysian grades with some oil from Australia, China and Vietnam regions. The Asia-Pacific region is both importer as well as exporter of crude but it is overall a net importer. The detailed list is given in Annexure 4.6.

Though there are wide disparities in the quality of the crude produced in the world, the regions can be broadly classified according to the quality of crude they produce as presented in table below. For the detailed classification of crudes, refer to Annexure 4.7.

Table 4.1 Classification of regional crudes

Region	Type of crude
North America	Sour
S & C America	Sour
Europe	Sweet
Former Soviet Union	Sweet
Middle East	Sour
Africa	Sweet
Asia-Pacific	Sweet

Benchmark for ONGC crudes

All ONGC crudes are sweet but they differ in gravity. Following are the broad characteristics of the crudes produced by ONGC from different fields.

Table 4.2 Characteristics of ONGC crudes

Crude	API	Sulphur
Bombay High	39.50	0.140
KG Basin	41.75	0.021
Cauvery Basin	40.60	0.040
South Gujarat	45.81	0.016
North Gujarat	25.68	0.096
Jorhat Assam	27.20	0.080
Moran Assam	34.77	0.080

Source: ONGC

Response from ONGC and refineries have yielded the following benchmarks for the ONGC crudes.

Table 4.3 Benchmarked crudes

ONGC crude	Benchmarked crude (share in the mix) (Country of origin)
Bombay High	Bonny Light (50%) (Nigeria) Escravos (50%) (Nigeria)
Cauvery Basin	Arab Light (Saudi Arabia)
South Gujarat	Bonny Light (Nigeria)
North Gujarat	Bonny Light (Nigeria)
Jorhat Assam	Bonny Light (Nigeria)
Moran Assam	Bonny Light (Nigeria)

Note. Since KG crude is processed by Tatpaka refinery of ONGC, crude from this region has not been considered in the analysis

Given that all ONGC crudes are sweet crudes, the following sections analyse the demand-supply and markets of sweet crudes in the world, identifies international demand for ONGC crudes and analyses the export potential of ONGC crudes.

Demand/supply of imported sweet crude

The following table shows the historical as well as projected consumption of crude oil by major regions of the world. The historical figures are from BP-Amoco Statistical Review of World Energy while the projected figures are from World Energy Outlook (WEO), Reference Case, published by Department of Energy, USA.

Table 4.4 Consumption by major regions (million tonnes)

Regions	1995	2000	2005	2010
North America	955	1065	1275	1374
Europe	723	753	812	832
Middle East	190	209	279	339
South and Central America	194	219	264	319
Africa	104	117	169	199
Former Soviet Union	217	173	244	279
Asia-Pacific	851	969	1185	1384
World	3235	3504	4228	4726

Source. BP-Amoco Alive, 2001; WEO, 2001

The following table shows the historical and projected production figures for the major regions of the world.

Table 4.5 Production by regions (million tonnes)

Regions	1995	2000	2005	2010
North America	647	652	802	802
Europe	311	329	383	378
Middle East	967	1112	1404	1633
South and Central America	294	348	418	468
Africa	341	373	493	578
Former Soviet Union	358	394	478	593
Asia-Pacific	350	381	324	324
World	3269	3590	4302	4775

Source. BP-Amoco Alive, 2001, WEO, 2001

Combining the above two tables, we have the following net surplus/deficit status as follows-

Table 4.6 Net Surplus(+)/Deficit (-) (million tonnes)

Regions	1995	2000	2005	2010
North America	-309	-413	-473	-573
Europe	-412	-424	-428	-453
Middle East	777	903	1125	1295
South and Central America	100	130	154	149
Africa	237	257	324	378
Former Soviet Union	141	221	234	314
Asia-Pacific	-501	-588	-861	-1061
World	34	86	75	50

As this table shows, North America, Europe and Asia-Pacific are projected to be net importers of crude oil while Middle East, Former Soviet Union, Africa and South and Central America are projected to be net exporters.

Assuming that the share of sweet crude in total imports remains the same, we can identify the demand for imported sweet crude of North America, Europe and Asia-Pacific regions. Africa and South & Central America, though surplus in crude oil, import some quantity of sweet crude. Assuming that the share of imported sweet crude will remain the same in total consumption of the countries, we can estimate the demand for imported sweet crude for these regions.

The following table shows the resulting demand for imported sweet crude for various regions.

Table 4.7 Demand for imported sweet crude (million tonnes)

Regions	2005	2010
North America	168	204
Europe	233	246
Asia-Pacific	117	144
Africa	13	15
South and Central America	21	25
Total	552	635

Table 4.7 also shows the regions which have a exportable surplus of crude. Using the classification given in table 4.1, we can project the supply of sweet crude as follows:

Table 4.8 Exportable surplus of sweet crude (million tonnes)

Regions	2005	2010
Africa	324	378
Former Soviet Union	234	314
Total	558	692

The following table shows the resulting demand supply balance of sweet crude for the coming decade.

Table 4.9 Demand-supply outlook for sweet crude (million tonnes)

	2005	2010
Demand	552	635
Supply	558	692
Net Surplus	6	58

Thus, there is a small surplus expected in the world for sweet crude.

North America

As shown in table 9.5, North America will be importing about 168 MMTPA of sweet crude in the year 2005. The table below shows the sources for its crude imports for the year 2000.

Table 4.10 Import sources for North America (million tonnes)

Countries/Region	Volume	% share
South & Central America	133.3	29.93
Middle East	129.7	29.12
Total Sour	263	59.05
Western Europe	72.0	16.16
Former Soviet Union	3.2	0.71
Africa	85.6	19.22
Asia-Pacific	14.2	3.18
Total Sweet	175	39.27
Unidentified*	7.3	1.63
Total	445.3	

Source. BP Amoco Alive, 2001

As shown in the table, Western Europe, FSU, Africa and Asia-Pacific together supplied about 175 MMTPA of crude to North America in the year 2000. The highest share among these is of Africa, which contributes around 50%, followed by Europe, which contributes around 42%.

As shown in table 4.6, Africa is projected to continue to have a huge surplus of sweet crudes, which means that in the coming decade, Africa will fulfil most of the North American demand for sweet crude.

Europe

Europe, in particular Western Europe, is a large trader of crude oil. In the year 2000, it imported 548.8 million tonnes of crude oil while it exported 96.8 million tonnes. With proven oil reserves of 2500 million tonnes, Europe holds 2% of the total world oil reserves.

The projected demand for imported sweet crude is about 233 MMTPA in the year 2005. Currently, the region imports around 561.5 MMTPA of crude of

which 53% is sweet and rest sour. The major import sources for the region are shown below-

Table 4.11 Import sources for Europe (million tonnes)

	Europe	% share
USA	10.1	1.84
Canada	0.6	0.10
Mexico	10.1	1.84
South & Central America	12.5	2.27
Middle East	192.5	35.07
Total Sour	225.8	41.12
Former Soviet Union	164.2	29.91
Africa	132.5	24.14
Asia-Pacific	1.5	0.27
Total Sweet	298.2	54.32
Unidentified*	24.8	4.51
Total	548.8	

Source. BP Amoco Alive, 2001

Among the sweet crude sources, the important ones are Africa and FSU. This is due to the fact that these regions are nearest to Europe and hence enjoy substantial freight advantage over the other sweet crude producing region in the world - Asia-Pacific.

As elaborated above, Africa will remain the major supplier of sweet crude to this region also and hence Europe is not a potential market for ONGC. Since European crude is also primarily sweet, an analysis of the export destinations of the same will identify the regions where ONGC can also sell its crude, given the freight economies.

The following table shows the export destinations of the European crude.

Table 4.12 Export destinations for European crude (million tonnes)

Country	Volume
USA	43.7
Canada	28.3
Mexico	0.2
S&C America	1.4
Africa	8.4
Australasia	0.1
China	2.6
Japan	0.3
Other Asia-Pacific	7.0
Rest of world	4.8
Unidentified	-
Total	96.8

Source. BP Amoco Alive, 2001

As is evident, North America accounts for a major portion of the European crudes. Going by the logistics, we can say that Africa and North America will find

it economical to import crude from Europe than from India. Asia-Pacific also imported 10 million tonnes of European crude in the year 2000. This probably represents the minimum market ONGC can cater to in the Asia-Pacific region. But whether it will be economical to export the crude oil for ONGC is examined later.

Asia-Pacific

Though Asia-Pacific, with proven reserves of 6000 million tonnes which constitutes 4.2 % of world reserves, exports some quantity of crude oil, it is a net importer. In the year 2000, it produced 380 million tonnes of crude oil but consumed 967 million tonnes.

Taking the reference case of the forecast for both production and consumption of crude oil by the regions as given by WEO, the demand for imported sweet crude for the Asia-Pacific region is estimated at 117 million tonnes. However, given the fact that India is projected to import around 38 million tonnes of sweet crude in the year 2005 (table 5.7), the residual demand in Asia-Pacific is reduced to 79 million tonnes.

FACTS* projects that though the use of sweet crudes in this region will be declining in the view of declining production of the same, the production will decline faster than consumption because of which the region will be importing around 75 million tonnes of sweet crude oil per annum in the year 2005. After adjusting for the fact that some of this demand is originating from India, the sweet crude import demand excluding India comes at around 36.31 million tonnes per annum.

Thus we can say that the total sweet crude demand in Asia-Pacific region, excluding India is expected to be in the range of 36.31 to 78 million tonnes in the year 2005.

Asia-Pacific exports

The table below shows the major export destinations of the region as a whole for the year 2000.

* FACTS Energy Advisory Number 255, June 2001

Table 4.13 Export destinations (Million tonnes)

Destination	Volume
USAs	14.1
Europe	1.5
Canada	0.1
South & Central America	0.3
Western Europe	1.5
Africa	0.2
Total	17.7

Source. BP Amoco Alive, 2001

However, much of the Asia-Pacific crudes are traded within the region. The intra-region exports amounted to about 122.5 million tonnes or 87.75% of the total crude oil consumed outside the country of origin in the region. Out of the 17.7 million tonnes going outside the region, USA accounts for 14.1 million tonnes and Western Europe accounts for 1.5 million tonnes. This is understandable since Western markets have access to nearer African and North Sea crudes, which are also sweet and have a freight advantage over the Asian crudes in these markets. Carrying the crude from Asia-Pacific to these regions will involve huge freight and hence have to be sold at a discount to remain competitive. They thus do not constitute a market for ONGC.

Asia-Pacific imports

The following table shows the important regions, outside Asia-Pacific, from where Asia-Pacific is importing its crude.

Table 4.14 Import sources for Asia-Pacific (million tonnes)

Regions/Countries	Volume	%
USA	6.1	0.9
Mexico	2.4	0.4
South & Central America	4.4	0.7
Middle East	559.8	83.9
Total Sour	572.7	85.9
Western Europe	10	1.5
Former Soviet Union	12.3	1.8
Africa	68.4	10.2
Total Sweet	90.7	13.5
Unidentified*	3.7	0.6
Total	667.1	

Source. BP Amoco Alive, 2001

As this table shows, Middle East is the dominant supplier of crude to Asia-Pacific region, accounting for about 84 % of total crude imports originating from outside the region. This is understandable given the fact that Asia-Pacific

produces primarily sweet crude and hence requires sour crude to obtain an economical product yield.

However, in so far as the crude oil production is lower than the consumption, the region also imported some sweet crude, primarily from Africa, which constituted about 10.2 % of the total Asia-Pacific imports from outside the region.

Intra-region imports, not shown in the table, are also substantial and contribute an additional 126.2 MMTPA.

Given the fact that ONGC crudes are primarily sweet and that India is situated at the far end of the Asia-Pacific region, it can be said that the market left for ONGC is that portion of the total imports which is supplied by Africa and North Sea. In the year 2000, about 68.4 million tonnes of crude oil was imported from Africa and about 10 million tonnes came from Europe which is mainly North Sea. Out of these total Asia-Pacific imports, India accounted for 14.7 million tonnes of African crude and 1.6 million tonnes of North Sea crude in the year 2000^a. Thus, the Asia-Pacific demand, excluding India, which ONGC could have catered is 62 million tonnes in the year 2000.

Africa

Nigeria

Nigeria currently holds proved crude reserves of 3100 million tonnes. Its reserves have been increasing over the years and now stand at 131% of the reserves at the end of 1990. Nigeria's main export crudes are Bonny Light and Forcados with 37 and 31 API respectively.

Last year, Nigeria produced 103.9 million tonnes of crude and consumed only 13.9 million tonnes, which leaves the exportable quantity of 90 million tonnes. Majority of this surplus is destined for United States (it was fifth largest exporter of crude to United States behind Saudi Arabia, Mexico, Canada and Venezuela in 2000) and Western Europe but Asia is increasingly becoming an important market. Following table shows the major markets for the Nigerian crudes.

^a Source: Oil Coordination Committee

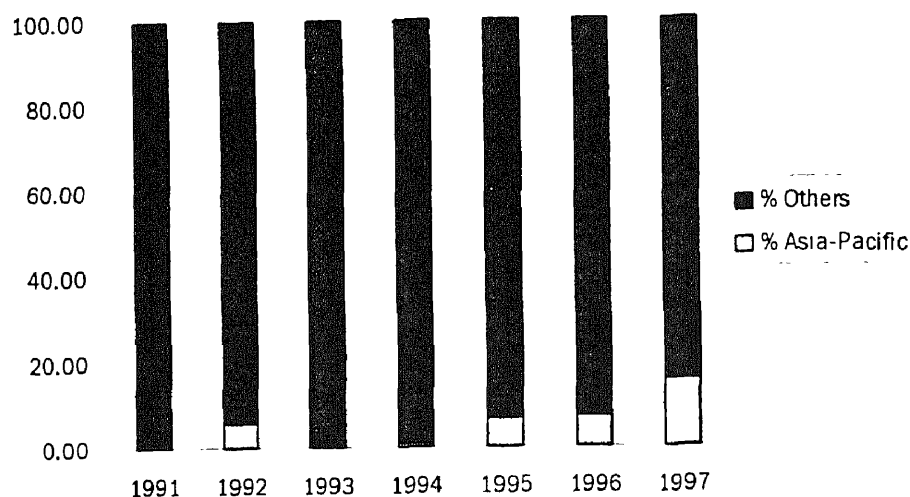
Table 4.15 Major markets for Nigerian crudes ('000 tonnes)

Country	1991	1992	1993	1994	1995	1996	1997
USA	33823	33492	35614	13515	37059	36750	41522
Japan	-	-	-	263	781	1002	1137
Germany	6793	8942	7689	6911	4623	3975	5072
Italy	2780	1663	615	877	590	1224	2007
France	4091	4491	5498	8210	1596	8246	4257
Korea	-	-	-	-	2592	3593	5027
Spain	11149	8574	6068	7050	8599	10417	9656
Netherlands	4244	3653	3905	5067	1874	3023	1900
United Kingdom	1629	1468	193	308	745	1568	214
Singapore	-	-	-	96	257	459	-
Belgium	436	83	269	580	36	-	-
Canada	2590	2586	4094	-	2872	1473	2292
Brazil	1603	130	-	650	379	1189	3729
India	757	4027	-	-	-	-	7518
Sweden	761	626	123	1113	1271	396	391
Greece	-	-	-	122	126	-	-
Thailand	-	-	-	-	70	-	-
Poland	-	-	123	-	-	-	118
Philippines	-	-	-	-	260	132	127
China	-	-	-	-	390	-	-
Finland	368	-	-	-	-	-	-
Portugal	1919	2325	2536	2788	3082	3426	2949
Austria	1712	-	-	-	-	-	-
Australia	-	-	-	-	-	312	291
Total	74655	72060	66727	47550	67202	77185	88207

Source: Energy Yearbook Database, United Nations, various editions

As this table shows, Nigeria has a diversified portfolio of export destinations but most of the countries are located either in Americas or in Western Europe. This is because of the proximity of the country to these markets. Out of total exports of 88 million tonnes, only 13.9 million tonnes or 15.84% was destined for the Asia-Pacific region in the year 1997. Out of these 13.9 million tonnes, 7.5 million tonnes came to India. Hence, only 6.4 million tonnes was exported to markets other than India. But as the chart below shows, Asia-Pacific is becoming an increasingly important market.

Figure 4.1 Regional shares



There has been a continuous rise in the share of Asia-Pacific region in the total Nigerian exports. Within the Asia-Pacific region, the main countries, apart from India, are Japan and Korea. Given the proximity of India to Japan and Korea compared to the West Africa, it may be said that, theoretically, ONGC can sell its crude oil in Korean and Japanese markets.

Angola

Angola is the fourth largest producer of crude oil in Africa with negligible consumption which leaves it with big exportable surplus. In the year 2000, it produced 36.40 million tonnes of crude oil, majority of which was exported. Recently, Girassol oil field, with estimated reserves of 1 billion barrels, achieved its peak output and will increase the supply to US and Asia-Pacific^a. Though Girassol falls within processing limits for most refineries in Asia-Pacific, most demand is expected from the US, where it will be valued as a feedstock in complex refineries. Moreover, its floating, storage, production and offloading vessel will be able to store 2 million barrel and allow VLCCs to load which would make long hauls more attractive. The Jasmim field is due on stream in 2003 as a satellite to Girassol and will help maintain its 200,000 b/d plateau. Thus, Angola has the potential to emerge as a major supply source for sweet crude.

^a Petroleum Argus Global Markets, Volume XXXII, 4, 28 January 2002.

Export feasibility for ONGC

While the above analysis shows a huge demand for imported sweet crude in the coming decade in various regions, the possibility of ONGC exporting is examined below.

Policy restriction

In the year 2000-01, India imported around 74 MMT of crude to satisfy its demand for petroleum products. Given this import dependency of 72 %, it is very unlikely that ONGC will be allowed to export its crude oil. The current EXIM policy does not allow free exports of crude oil. Even the private producers under various rounds of NELP are not allowed to export their crude. Thus, it may happen that ONGC is forced to sell its crude within India only.

Low volume and declining reserves

ONGC produces only about 23 MMT of crude oil per year which translates into 461 thousand barrels per day while the average production in Africa is 711 thousand barrels per day respectively.

Moreover, ONGC's reserves are not projected to grow over the last few years. While Middle East and Africa have added around 21 and 15 thousand million barrels in proven reserves in the decade 1990-2000, India has seen a decline in proven reserves by around 3.3 thousand million barrels over the same time period^a.

Export infrastructure

Fields such as North and South Gujarat and Assam are landlocked fields and hence crude from these locations cannot be exported except at a great cost of setting up the required pipelines and other facilities.

The production of KG and Cauvery basin crudes does not constitute a case for exports.

Bombay High is in a slightly better position since it is offshore and has a stabilisation unit at Uran. But ONGC faces a bottleneck in terms of limited DWT of the Jawahar Dweep port. The maximum size of ship it can accommodate is 47000 dwt while the capacity of VLCC ranges from 160,000 dwt to 319,000 dwt. Thus, ONGC can't load a VLCC tanker from Jawahar Dweep port and hence it would be uneconomical for it to export the crude.

^a Data from BP-Amoco Alive, 2001

One of the important market Asia-Pacific region, Japan, imports huge quantities of crude oil from Middle East and hence cannot be replaced by ONGC. It also imports some quantity from other countries in Asia-Pacific region. They being nearer to Japan have a freight advantage over India. Then Japan mostly imports the crude oil in ULCC tanker, which cannot be loaded in any Indian port.

Quality considerations

The level of BS&W in the ONGC crudes is well above the international norms.

Table 4.16 BS&W in ONGC crudes

Crude	BS&W (% vol)
Bombay High	0.1
North Gujarat	0.3
South Gujarat	0.5
Krishna Godavan Basin	0.3
Cauvery Basin	-
Jorhat	0.1
Moran	0.2

Thus, if ONGC were to export this crude, it would have to discount it heavily in order to remain competitive.

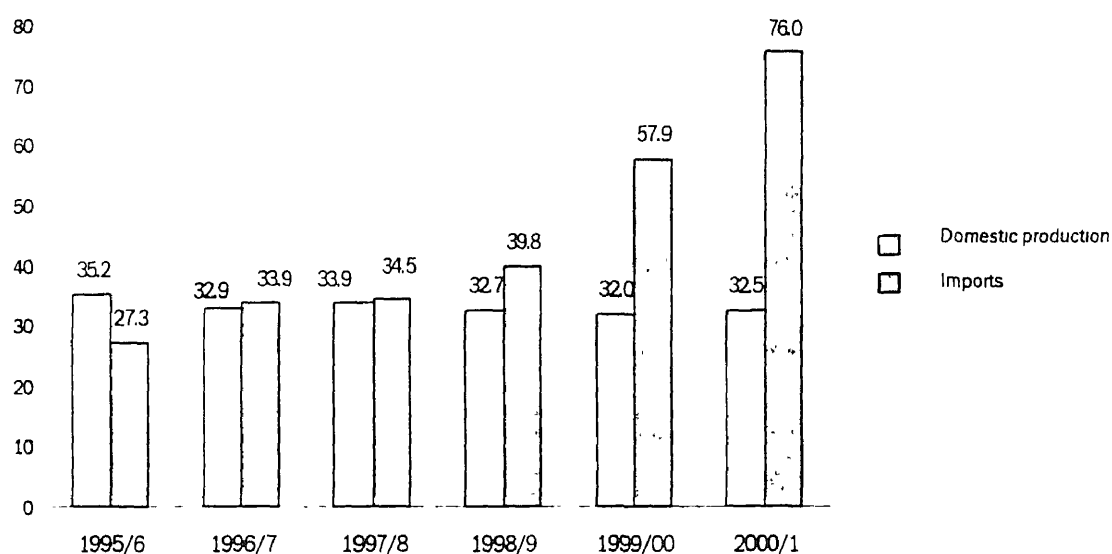
North Gujarat crude has a high degree of naphthenic acid, which corrodes the refinery infrastructure. This would render this crude unacceptable in the international market.

In the international market, all these factors will lead to some discounting of ONGC crudes due to which ONGC will find it economical to sell the crude oil domestically.

Import dependence

India is largely dependent on imported crude oils and imports show an increasing trend over the years as is evident from Figure 5.1.

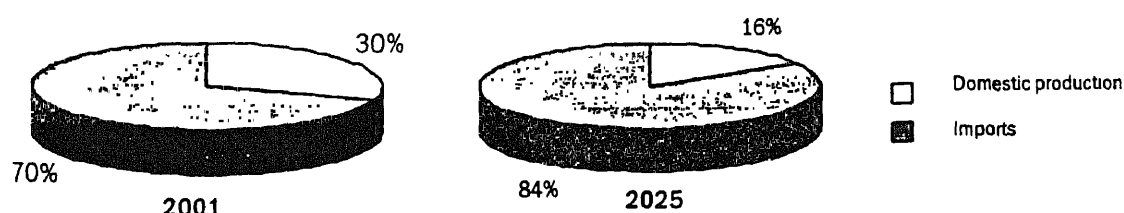
Figure 5.1 Trend in domestic crude oil production and imports (MMT)



Source: CMIE

The Hydrocarbon Vision 2025 (HC Vision) projects India's requirement of petroleum products to be about 370 MMTPA in 2025. The HC Vision expects domestic crude production in 2025 to be about 60 million tonnes. The balance crude requirement has to be bridged by imports. Thus, crude imports to India in 2025 can be estimated to be about 310 MMT. This implies that share of imports in total oil requirement will rise from about 70% at present to about 84% in 2025.

Figure 5.2 Dependence on crude oil imports

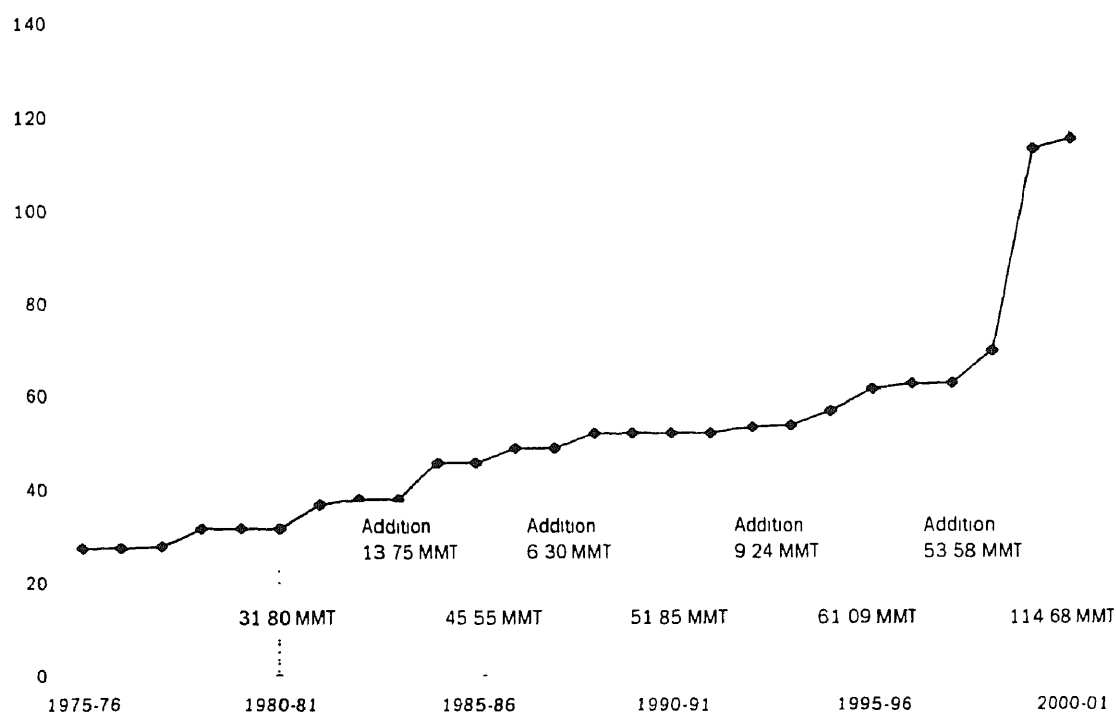


In this section we concentrate on a short term outlook on crude oil imports - till 2006/7 and largely consider the assumptions made by the Tenth Plan.

Refining capacity in India and projected growth

Figure 5.3 below shows the historical growth of refining capacity in India.

Figure 5.3 Historical growth of refining capacity in India (MMT)



At present there are 17 refineries in India with a total refining capacity of about 114.7 MMT. The refinery-wise installed capacity is presented in Table 5.1 below.

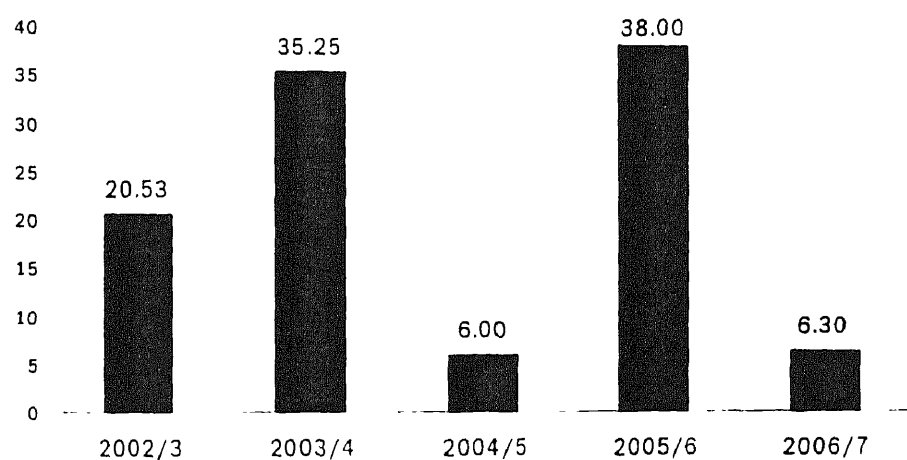
Table 5.1 Refining capacity in India 2001

Company	Location	State	2000/01
West			
BPCL	Mumbai	Maharashtra	6.9
HPCL	Mumbai	Maharashtra	5.5
North and North-west			
Reliance	Sikka	Gujarat	27
IOC	Koyali	Gujarat	13.7
IOC	Panipat	Haryana	6
IOC	Mathura	Uttar Pradesh	8
East			
IOC	Barauni	Bihar	4.2
IOC	Haldira	W Bengal	4.6
North-east			
IOC	Guwahati	Assam	1
IOC	Digboi	Assam	0.65

BR&PL	Bongaigaon	Assam	2.35
IBP/BPCL	Numaligarh	Assam	3
South			
MRL	Madras	Tamil Nadu	6.5
CRL	Cochin	Kerala	7.5
MRL	Nanmanam	Tamil Nadu	0.5
HPCL	Vizag	Andhra Pradesh	7.5
HPCL/Birla	Mangalore	Karnataka	9.69
ONGC	Tatipaka	Andhra Pradesh	0.078
Total			114.668

Considering all the projects under implementation and planned, the Xth Plan projects that the refining capacity in India may be about 220.7 MMT by 2006/07. The year-wise possible capacity additions, as per the Xth Plan, are illustrated in Figure 5.4 below. Refinery-wise details of planned capacity additions under the Xth Plan are presented in table 5.2.

Figure 5.4 Refinery capacity additions (MMT) as planned under Xth Plan



Source. Tenth-Plan subgroup report on refining

Table 5.2 Capacity additions planned/under implementation in Xth Plan period

Year	Refinery	Company	MMTPA
2002-03	Barauni	IOC	1.80
	Haldia	IOC	1.40
	Mumbai	HPCL	0.33
	Nanmanam	CPCL	0.50
	Jamnagar	RPL	6.00
	Jamnagar	Essar	10.50
Sub total			20.53
2003-04	Koyali	IOC	4.30
	Panipat	IOC	6.00
	Mumbai	BPCL	5.10

Year	Refinery	Company	MMTPA
	Chennai	CPCL	3.00
	Bongaigaon	BRPL	0.35
	Paradip	IOC	9.00
	Jamnagar	Essar	1.50
	Cuddalore	NOCL	6.00
	Sub total		35.25
2004-05	Kochi	KRL	6.00
	Sub total		6.00
2005-06	Jamnagar	RPL	17.00
	Jamnagar	Essar	12.00
	Bathinda	HPCL	9.00
	Sub total		38.00
2006-07	Bongaigaon	BRPL	0.30
	Bina	BORL	6.00
	Sub total		6.30
	Total X Plan		106.08

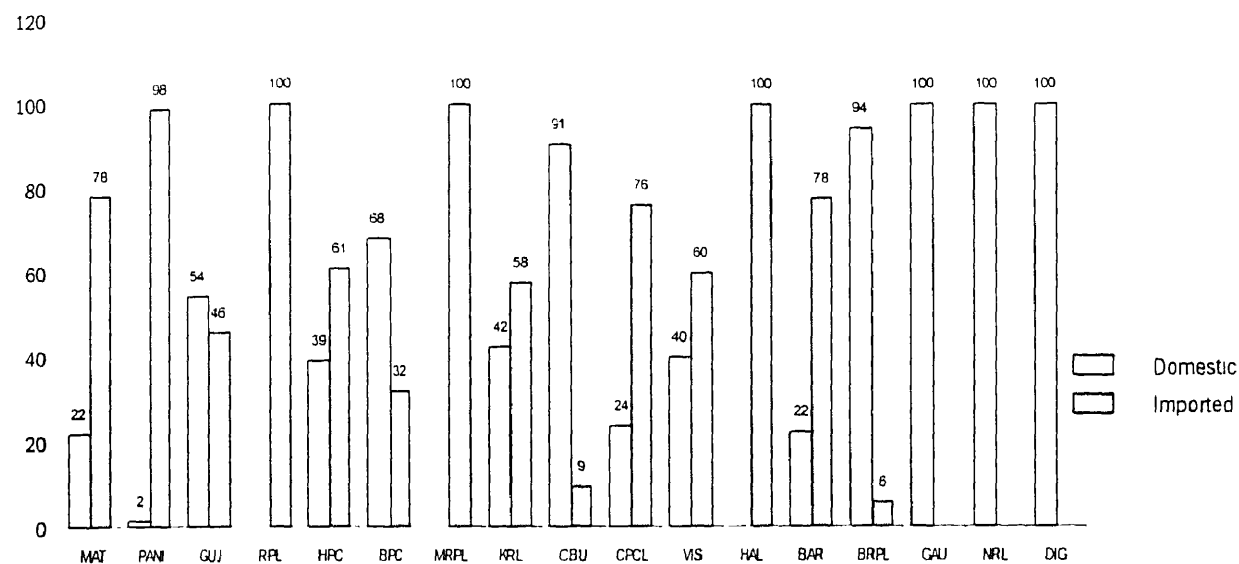
However it is uncertain as to which projects will materialise over the time period. As seen from the historical build-up of refining capacity in the country (Figure 5.3), the maximum capacity addition had been in the last 5 years to the extent of 54 MMT. Thus the Xth Plan targets of capacity addition seems overestimated. Also, in view of the emerging surplus situation in some of the petroleum products, a 106 MMT capacity addition in the coming 5 years seems improbable. However, capacity addition in India is somewhat politically influenced and it cannot be ascertained as to which of the projects will materialise and in what time frame.

Crude use pattern of existing refineries

The crude throughput by the refineries in 2000-01 had been a little over 103 MMT. In this about 72 MMT was imported and 30 MMT was from indigenous fields. Annexure 5.1 provides crude-wise throughput by refineries in 2000-01.

Domestic crude

The north-eastern refineries of Numaligarh, Guwahati and Digboi and the southern refinery of Narimanam use entirely domestic crude oils, whereas all other refineries are importing a hefty percentage of their crude oil requirement. In 2000/1 only 28% (28.9 MMT) of the crude intake was domestically produced, whereas 72% (74.2 MMT) had to be imported. The percentage of domestic and imported by refineries has been illustrated below.

Figure 5.5 Percentage of domestic and imported crude oil use by different refineries

Source. OCC

Source of crude oil imports to India

Historically most of the crude imports are sourced from the Middle East region. The next largest exporter to India being Africa, especially Nigeria, followed by the Far East country of Malaysia.

*Sweet and sour crude intake***Current pattern of crude use by refineries**

Among imported crudes, those from Africa are largely sweet having sulphur content in the range of 0.1 – 0.3% by weight, whereas those from the Middle East Gulf region are largely sour crudes having sulphur content in the range of 1.5 – 3%.

Table 5.3 provides the major crudes and sources of crude imports to India in 2000-01. Figure 5.6 maps the crude-wise intake by the existing refineries.

Figure 5.6 Crude oil use by existing refineries

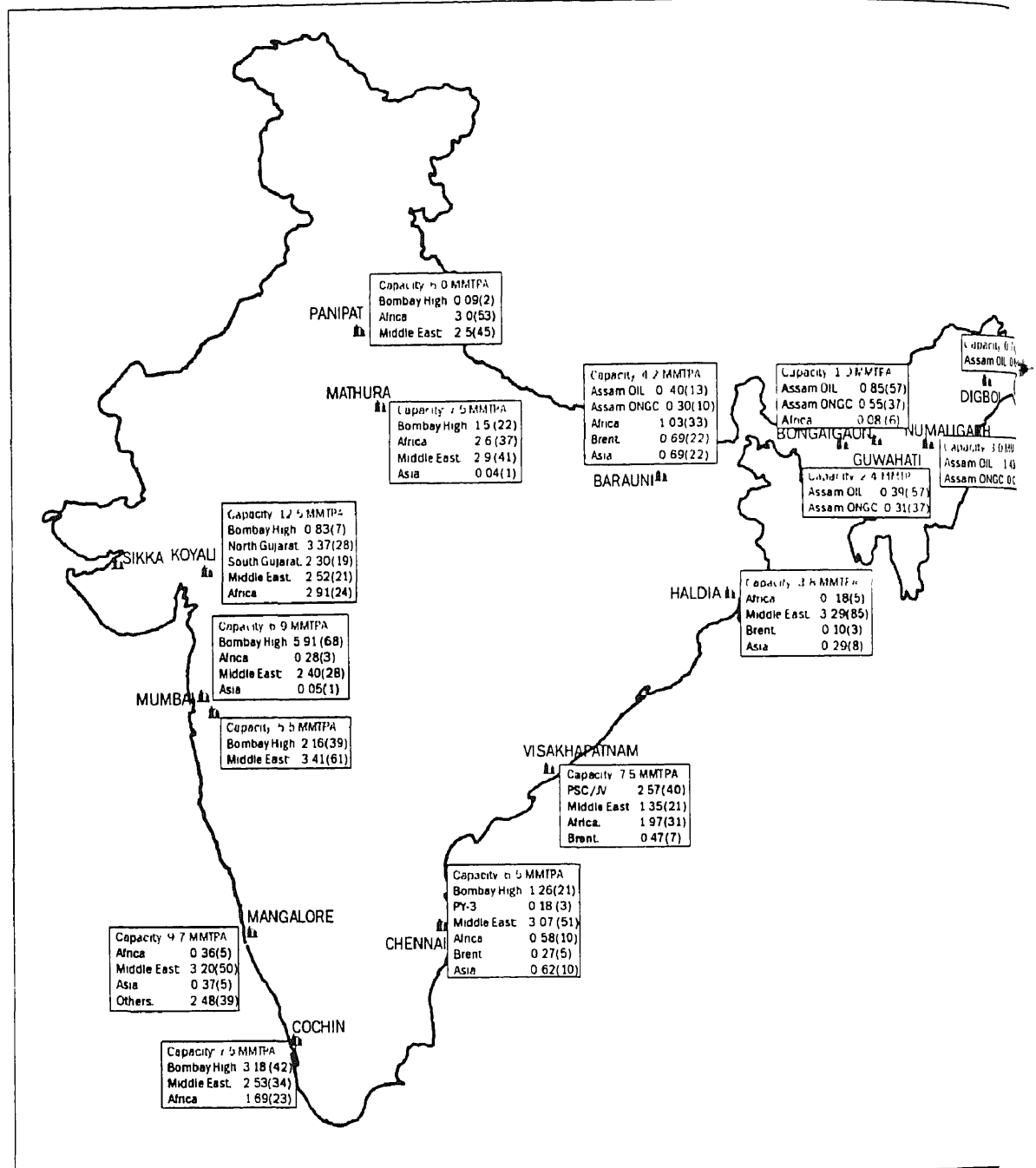


Table 5.3 Major crudes imported by India in 2000-01

Crude	Source	API	Sulphur
High sulphur			
Arab Mix (80 20) and Arab Extra Light	Saudi Arabia	27 85-33 23	2.81-1 90
Basra Light	Iran	32.56	2.18
Iran Mix	Iraq	30 68-32 56	1 50-1.92
Kuwait	Kuwait	30.40	2 59
Dubai	UAE	31.14	1.94
Murban	UAE	39.29	0.80
Umm Shaif	UAE	33.80	1.14
Upper zakum	UAE	37.40	1.51
Lower zakum	UAE	33.23	1.89
Oman	Oman		
Qatar land	Qatar		
Masila	Yemen	31.05	0.54
Suez Mix	Egypt	32.00	1.50
Zeit Bay	Egypt		
Low sulphur			
Qua Iboe	Nigeria	36.00	0 10
Escravos	Nigeria	36.00	0.10
Forcados	Nigeria	29.70	0.29
Bonny Light	Nigeria	37.00	0.10
Es Sider	Libya	36.70	0.37
Palanca	Angola	37.15	0.18
Soyo Blend	Angola	34.00	0.20
Cabinda	Angola	32.00	0.20
Nemba	Angola	38.78	0.17
Labuan	Malaysia	31.61	0.08
Min Light	Malaysia	32.37	0.08
Tapis	Malaysia	45.27	0.03
Badin	Pakistan		
Brent Blend	Europe		

Among imported crudes, in 2000-01, the percentage of low sulphur and high sulphur crudes were 26% and 74% respectively. Considering the entire domestic production is of low sulphur, in the total crude usage by refineries, the percentage of low and high sulphur was of the order 47% and 53% respectively. The pattern of high and low sulphur crude use by refineries in 2000-01 is tabulated below.

Table 5.4 Pattern of low and high sulphur crude use by refineries in 2000-01

Region	Refinery	Crude Throughput	Low Sulphur		High Sulphur		Imported crudes	
		(TMT)	(TMT)	%	(TMT)	%	LS %	HS %
West	HPC	5575	2165	39	3410	61	0	100
	BPC	8664	6208	72	2456	28	11	89
	GUJ	12005	9162	76	2843	24	48	52
	RPL	25716	0	0	25716	100	0	100
South	KRL	7520	4771	63	2749	37	37	63
	CPCL	6046	2935	49	3111	51	32	68
	VIS	6407	4927	77	1480	23	61	39

Region	Refinery	Crude Throughput	Low Sulphur		High Sulphur		Imported crudes	
		(TMT)	(TMT)	%	(TMT)	%	LS %	HS %
North	MRPL	6438	2550	40	3888	60	40	60
	CBU	579	579	100	0	0	100	0
	MAT	7134	3968	56	3166	44	43	57
	PANI	5708	2899	51	2809	49	50	50
East	BAR	3122	3122	100	0	0	100	0
North-east	HAL	3875	584	15	3291	85	15	85
	GAU	707	707	100	0	0	0	100
	DIG	679	679	100	0	0	0	100
	BRPL	1490	1490	100	0	0	100	0
	NRL	1451	1451	100	0	0	0	100
India	Total	103116	48197	47	54919	53	26	74

Future outlook on domestic production and oil imports

Domestic production

As evident from Figure 5.7, domestic crude oil production shows a stagnating trend and the Xth Plan projects that the trend will continue over the plan period with an average production of 32 MMTPA till 2006/7. According to the Xth Plan, domestic crude available for processing by the refineries is estimated to be 31.6 MMT in 2006-07.

Table 5.5 Indigenous crude oil production targets

	2002-03	2003-04	2004-05	2005-06	2006-07
Assam					
OIL	3.500	3.600	3.750	3.850	4.000
ONGC	2.013	2.057	2.066	2.054	2.004
JVC	0.061	0.061	0.061	0.061	0.061
Gross	5.574	5.718	5.877	5.965	6.065
Net	5.146	5.278	5.426	5.507	5.600
Gujarat					
Gross	6.000	6.075	5.963	5.962	5.828
Net	5.928	6.002	5.891	5.890	5.758
Bombay High					
Gross	14.767	16.014	16.342	16.485	16.271
Net	14.235	15.437	15.754	15.892	15.685
South					
Gross	0.520	0.471	0.393	0.331	0.285
Net	0.518	0.469	0.391	0.330	0.284
Other JVC					
Gross	3.548	3.498	4.368	4.308	4.278
Net	3.509	3.460	4.320	4.261	4.231
Total					
Gross	30.409	31.776	32.943	33.051	32.727
Net	29.336	30.646	31.782	31.880	31.558

Source. Tenth-Plan subgroup report on refining

Crude oil imports

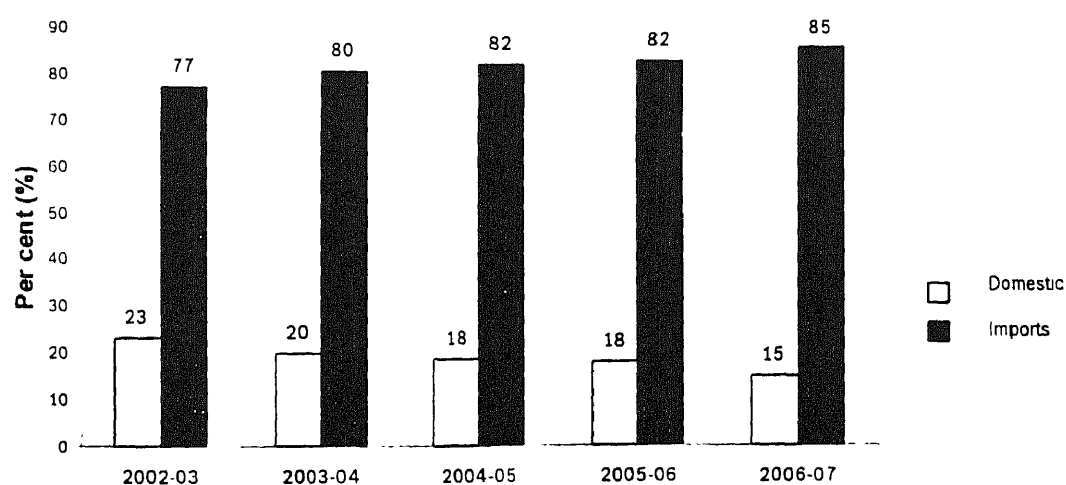
The gap between indigenous crude oil availability (31.6 MMT) and the need for processing in 2006-07 will have to be bridged by imports. In view of the surplus situation emerging in some petro-products, the Xth Plan also provides a base case estimate of crude imports, considering materialisation of 70% of projected refinery capacity additions and 90% utilisation of capacity. The processing requirements and the gross import requirements as projected by the Xth plan – the high and base case scenarios is provided in Table 5.6 below.

Table 5.6 Crude oil processing and imports (MMT) during Xth Plan

	2002-03	2003-04	2004-05	2005-06	2006-07
High Case					
Total processing need	127.672	154.906	174.081	181.392	213.806
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	98.336	124.26	142.299	149.512	182.248
Gross imports	98.83	124.884	143.014	150.264	183.163
Base Case					
Total processing need	117.572	142.247	146.447	173.047	177.457
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	88.236	111.601	114.665	141.167	145.899
Gross imports	88.679	112.162	115.241	141.876	146.632

Figure 5.7 below shows the percentage of imported oils in total oil processed (high case scenario). Thus the Xth Plan projections imply increasing share of imported crude oils in total oil needs as refinery capacity is projected to increase substantially and domestic crude production to remain more or less stagnant.

Figure 5.7 Share of imported and domestic crude oils in total processing requirement – high case



Sweet and sour crude intake

The Xth Plan projections

The Xth Plan projects high and base case scenarios of the quantity of high and low sulphur crude oils to be imported in future based on the crude mix as indicated by refineries. This information is tabulated in table 5.7 below. The percentage of low and high sulphur oils in total imports is also listed. Considering all indigenous production to be of low sulphur, the share of low and high sulphur crudes in total processing needs is also indicated in table 5.7 below.

Table 5.7 Share of high and low sulphur oils in total crude requirements

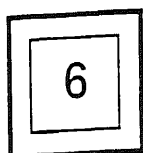
	2002-03	2003-04	2004-05	2005-06	2006-07
High case					
Total processing need	127.672	154.906	174.081	181.392	213.806
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	98.336	124.26	142.299	149.512	182.248
High sulphur	70.499	87.375	102.023	107.617	142.774
Low sulphur	27.837	36.885	40.276	41.895	39.474
HS %	55	56	59	59	67
LS %	45	44	41	41	33
Gross imports	98.83	124.884	143.014	150.264	183.163
High sulphur	70.853	87.814	102.536	108.158	143.491
Low sulphur	27.977	37.07	40.478	42.106	39.672
HS %	72	70	72	72	78
LS %	28	30	28	28	22
Base case					
Total processing need	117.572	142.247	146.447	173.047	177.457
Indigenous	29.336	30.646	31.782	31.88	31.558
Imported	88.236	111.601	114.665	141.167	145.899
High sulphur	64.922	80.235	85.828	102.666	118.501
Low sulphur	23.314	31.366	28.837	38.501	27.398
HS %	55	56	59	59	67
LS %	45	44	41	41	33
Gross imports	88.679	112.162	115.241	141.876	146.632
High sulphur	65.248	80.638	86.259	103.182	119.096
Low sulphur	23.431	31.524	28.982	38.694	27.536
HS %	74	72	75	73	81
LS %	26	28	25	27	19

Thus over the years the 70:30 share of high and low sulphur crudes in total imports is expected to be maintained.

Conclusion

In view of increasing dependence on imports, it can be concluded that entire domestic production of ONGC can be absorbed by the Indian market. The Xth Plan projects that over the years low sulphur oil has to be imported, thus it is expected that there will be no dearth of market for low sulphur domestic crude.

Also, the emission-environment norms are getting stricter to reduce pollution. Thus sulphur content in petroleum products like MS and HSD has to be reduced to meet the more stringent norms. According to the Xth Plan one of the ways to reduce sulphur content in MS is to process more of low sulphur crudes. This indicates a rise in demand for low sulphur crudes. The sulphur content norms of various petroleum products as laid down in the Xth Plan is summarised in Annexure 5.2.



Crude oil supply infrastructure to Indian refineries

It is important to analyse the existing domestic linkages from various oil fields to the refineries in order to identify the possible infrastructure bottlenecks in marketing in the deregulated era. Oil fields can be linked to refineries via three routes – pipeline, sea (tanker) and/or road.

Domestic crude oil is supplied to refineries mainly via pipelines or shipped from the fields to the refineries except the crude oil from the Chennai refinery which is moved by road to the Narimanam refinery.

BPCL and HPCL refineries - Mumbai

Domestic crude oil

Oil from the Bombay High, Heera, Neelam, Ratna, Panna and Mukta fields are brought by pipelines to Uran CTF and supplied to the HPCL and BPCL refineries via pipelines. Specifications of the major pipelines have been presented in Table 6.1 below.

Table 6.1 Crude oil pipelines from Western offshore fields to refineries in Mumbai

Pipeline	Length (km)	Diameter (Inches)	Owned By	Cost of Transportation (Rs/MT)	Capacity (Design flow)	Throughput (MMTPA)	Capacity Utilization (%)	Replacement Cost (Rs crores)
BH - Uran	203	30	ONGC	74.94	20 MMTPA	10.631	53.155	557
Heera-Uran	81	24	ONGC	74.94	8 MMTPA	5.074	63.425	179
Uran - Trombay	24	36	ONGC		5.54x10 ⁶ KG/HR	-	-	-
Trombay - BPCL	1.5	24	ONGC	37.00	4.4x10 ⁶ KG/HR	-	-	1.66
Trombay - HPCL	1	24	ONGC	37.00	4.4x10 ⁶ KG/HR	-	-	0.8

Source: OCC

It is evident from the capacity utilisation figures that the pipelines from Bombay High fields are grossly underutilised.

Imported crude oil

Imported crude oils from Middle East and Africa lands at either Vadinar (in the monsoon season) and distributed to the Mumbai refineries or comes to the

Pirpau jetty. From the Pirpau jetty it is carried via pipelines to the Mumbai refineries of HPCL and BPCL. The charter-hire shipping charges from Vadinar to Mumbai have been presented in Annexure 6.1. Pirpau jetty specifications has been listed in Table 6.2 respectively.

Table 6.2 Crude handling facilities of Mumbai port

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
Mumbai	Pirpau Oil Pier (1)	7.50	174	35000	14	28
	New Pirpau Pier (1)	12.00	197	47000	74	67

Source. Basic Port Statistics of India, Ministry of Surface Transport, 1999-00.

Koyali, Mathura and Panipat refineries

Domestic crude oil

Bombay High crude is shipped to Vadinar (at the 2 SBMs near Vadinar) from Jawahar Deep, fed into the Salaya-Mathura Pipeline (SMPL) and supplied to Koyali, Mathura and Panipat refineries. The trans-shipment charges from Mumbai to Vadinar have been presented in Annexure 6.1. North and South Gujarat crudes are supplied from the Navagam and Ankleshwar CTFs respectively to Koyali only. The Vadinar port facilities and crude pipeline infrastructure in the north-western region is presented in Tables 6.3 and 6.4 respectively.

Table 6.3 Crude handling facilities of Vadinar port

Port	Type of berth (No.)	Maximum size of ships (DWT)	% occupancy	
			1998-99	1999-00
Vadinar	SBM (2)	No restriction	49	54

Source. Basic Port Statistics of India, Ministry of Surface Transport, 1999-00.

Table 6.4 Crude oil pipelines to Koyali, Mathura and Panipat refineries

Pipeline	Length (km)	Diameter (Inches)	Owned By	Cost of Transportation (Rs/MT)	Capacity (MMTPA)	Throughput (MMTPA)	Capacity Utilization (%)	Replacement Cost (Rs crores)
Kalol - Navagam CTF - Koyali	130	14	ONGC	70.66	8	3.36	42	50.25
Ankleshwar - Koyali	94.77	16	ONGC	70.66	3	2.49	83	39.98
SBM1&2 - Vadinar	-	42	IOC	-	-	-	-	-
Vadinar - Viramgam	273	28	IOC	76.14	21	-	-	-
Viramgam - Koyali	141	18	IOC	-	6.5	6.382	98	-
Viramgam - Chaksu	606	24	IOC	84.22	13.5	-	-	-
Chaksu - Mathura	197	24	IOC	-	7.5	7.086	94.48	-
Chaksu - Panipat	346	24	IOC	-	6	5.533	92.22	-

Source. OCC

Imported crude oil

Imported oils for these refineries land at Vadinar are fed into the SMPL line.

Mangalore refinery

This refinery in the joint sector imports its entire crude requirement.

Table 6.5 Crude handling facilities of Mangalore port

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
New Mangalore	MRPL Crude jetty (1)	13.00	320	85000	60	60

Source: Basic Port Statistics of India, Ministry of Surface Transport, 1999-00.

Table 6.6 Crude oil pipelines to Mangalore refinery

Pipeline	Length (km)	Owned By	Capacity (MMTPA)
Mangalore jetty - refinery	11	MRPL	5000 (T/hr)

Source: HPCL

Cochin refinery

Other than imported crudes, Koch refinery uses Bombay High which is shipped to the Cochin port. The freight charges have been presented in Annexure 6.1.

Table 6.7 Crude handling facilities of Cochin port

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
Cochin	Oil terminal (1)	11.70	250	86000	64	97

Source: Basic Port Statistics of India, Ministry of Surface Transport, 1999-00.

CPCL refineries of Manali and Narimanam

Domestic crude oil

Manali refinery uses Bombay High as well as PY-3 (Cauvery) crude. The Narimanam refinery consumes Narimanam, Bombay High, PY-3 and KG onshore crudes. Though it is commonly called the Narimanam refinery, the actual location is Panangudi from where the refinery is connected to the Narimanam oil field via pipeline. Bombay High and PY-3 crudes are brought by road from Chennai. The crude supply routes are detailed in Table 6.8.

Table 6.8 Crude transport routes to CPCL refineries

	Route	Cost of Transportation (Rs/MT)	Capacity (MMTPA)	Throughput (MMTPA)	Capacity Utilization (%)	Replacement Cost (Rs crores)
Nanmanam-Panangudi	Pipeline (ONGC)	7.17	1			1.5
Manali - Nanmanam	Road	0.85/MT/KM				

Imported crude oil

Both the refineries are using imported oils. To the Narimanam refinery, imported oils are brought by road from Chennai.

Visakhapatnam refinery*Domestic crude oil*

Vizag refinery consumes Ravva offshore crude from the KG Basin. This oil is brought from Ravva fields to Suryasaya Yanam and from there on to the refinery.

Imported crude oil

Imported crude lands at Vizag port and transported thereon to the refinery. The Vizag crude handling capacity has been presented in Table 6.9.

Table 6.9 Crude handling facilities of Vizag port

Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
Vizag	Liquid Bulk berth-1	10.1	183	36000	76	83
	Liquid Bulk berth-2	9.80	183	36000	82	78

Table 6.10 Crude oil pipelines to Vizag refinery

Pipeline	Length (Km)	Diameter (inches)	Owned by	Cost of Transportation (Rs/MT)	Capacity	Throughput (MMTPA)	Capacity Utilization (%)
Ravva - S.Yanam	11.5	12	ONGC	-	-	-	-
Vizag Jetty - refinery	9.2	36	HPCL	67 275	5500 (T/hr)	-	-

Eastern and North-eastern refineries*Domestic crude oil*

The Digboi, Numaligarh, Guwahati and Bongaigaon refineries consume only indigenous oil from the north-east fields. The crude oil supply network to these refineries is presented in Table 6.11.

Table 6.11 Crude oil pipelines in the north-eastern region

Pipeline	Length (km)	Diameter (Inches)	Owned By	Cost of Transportation (Rs/MT)	Capacity (MMTPA)	Throughput (MMTPA)	Capacity Utilization (%)	Replacement Cost (Rs crores)
Narkhatiya - Digboi	36	8	OIL	5.27	0.5	0.469	93.8	360
Narkhatiya-Moran	51	-	OIL	7.46	1.75	2.447	139.8	10500
Moran-Jorhat	82	-	OIL	12	3.75	3.455	92.1	-
Jorhat CTF-Numaligarh	65	14	-	-	-	-	-	-
Jorhat-Guwahati	268	-	OIL	39.28	4.7	4.293	91.3	-
Guwahati-Bongaigaon	156	-	OIL	22.82	4	3.431	85.8	16000
Bongaigaon-Barauni	600	-	OIL	87.79	3	1.713	57.1	-
Haldia jetty-refinery	2x2.7	32	-	-	-	-	-	-
Haldia - Barauni	524.83	18	IOC	461.5	4.2	2.556	60.9	-

Imported crude oil

78% of the crude throughput by Barauni refinery in 2000/1 had been imported and only 22% had been domestic input. For the Barauni refinery imported crude lands at Haldia. Haldia refinery processed entirely imported crudes. The Haldia crude handling facilities have been depicted in table 6.12 below.

Table 6.12 Crude handling facilities of Haldia port

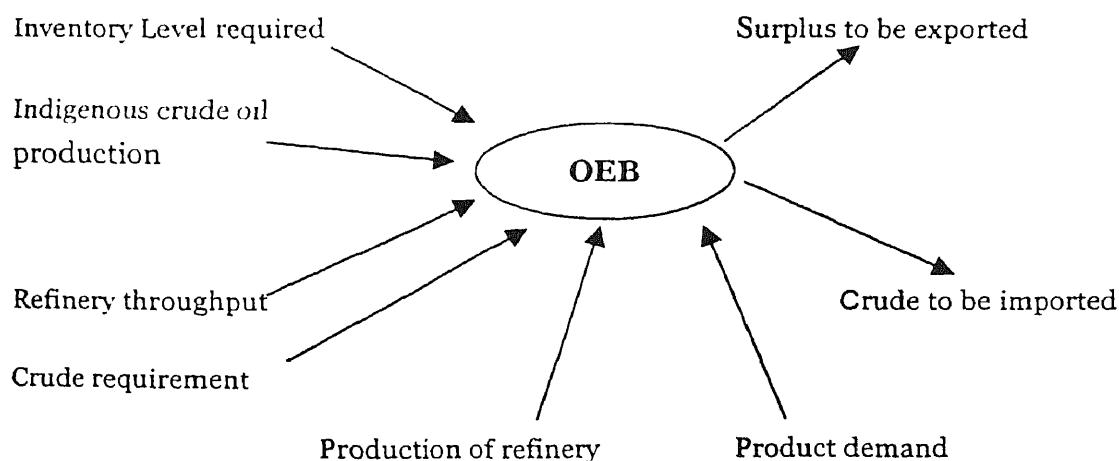
Port	Type of berth (No.)	Draft (mtrs.)	Length (mtrs.)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
Haldia	Liquid Bulk berth-1	12.20	91.44	90000	67	63
	Liquid Bulk berth-2	12.20	145	150000	60	69

Meeting crude oil requirements of refineries: the policy context

Crude oil requirement by refineries

Crude oil requirement by refineries over and above domestic availability is imported. Private and joint sector refineries has been independently importing their crude oil requirements without any government guidance. Recently, even PSU refineries like HPCL and BPCL have been allowed to import their crude oil. Following this, refineries like HPCL and BPCL had set up international trading cell and were preparing themselves for decontrol. HPCL has even concluded crude purchase agreement with Libyan national oil company for the purchase of 3.2 lakh tonne of crude per annum. BPCL is also preparing to source crude independently and is in the process of lying up supply contracts with Saudi Aramco, Yemen Oil and Gas and Kuwait Petroleum.

The allocation of domestic crude oil to refineries is decided by OCC, based on refinery specific requirements (refinery configuration), demand for products and yield of crudes and proximity of refinery and domestic fields. The quantity of imports for PSU refineries are based on the Oil Economy Budget (OEB) prepared by OCC. The Oil Economy Budget generally consists of the following:



Product demand forecasts are made on monthly basis. Demand for products and inventory requirement guide the refinery production plans and these in turn aid the assessment of crude oil requirement. Quantity required over and above domestic supplies is imported either by term contracts, through term tenders or through spot purchases. Existing policy for crude oil imports is elaborated later in the chapter.

The amount of crude oil required to be imported, type of crude oil necessary, suitable time for procuring crude, time of floating tenders and scheduling of ships are all linked parameters. Factors taken into account while planning crude procurement activities and distribution to various refineries have been listed below. There can be various other factors affecting actual refinery operations.

- crude oil storage capacity
- type of crude to be procured depends on its yield pattern and the petroleum products in demand at that point of time
- amount of the oil to be procured depends not only on demand for its products but also crude already in store
- oil procurement from a particular region depends on availability from that source and loadport conditions
- infrastructure of the refineries – charging tanks, crude distillation units, pipelines from ports to refinery, storage capacity at ports etc
- several issues have to be regarded while deciding the appropriate time of floating tenders
 - administrative delays
 - time taken to arrange for tankers
 - voyage time from the crude source to India leaving enough time

for unforeseen slippage. Average voyage times from different sources to India have been tabulated below.

Table 7.1 Average voyage time from various sources to India

Source	Destination	Average voyage time (days)
Middle East	Kandla	5
	Kochi	6
	Haldia	9
Malaysia	East coast India	5
Venezuela	West coast India	45
Africa	East coast India	20
	West coast India	22

- tanker unloading time and possible demurrage delays (average unloading time is 2 days)
- refinery processing time

- time taken for distribution of products.
- proper scheduling of tankers can reduce demurrage costs.

Pre-deregulation policy for crude oil imports for PSUs

The Empowered Standing Committee (ESC) was constituted in the late 1980's to organise crude oil imports through bilateral negotiations with the National Oil Companies or through the tender procedure.

Under the existing system, the quantities and value of import/export of crude oil and petroleum products are assessed on an annual basis. In 1998, the Government permitted the private sector refineries to import their requirement of crude oil directly. Until recently, IOC was the sole canalising agency for import of crude oil and various petroleum products for the PSUs.

The major crude oil markets for India are the Middle East, Africa and Far East regions. The other crude oil markets like Venezuela, Mexico, Vietnam etc., have not been very competitive for import of crude oil mainly due to freight diseconomy. However, lately some of these countries have been offering discounts of about \$2-5/bbl on the crude price, which may outweigh the freight economics argument.

The quantity and value of crude oil imports from 1990-91 onwards is presented below.

Table 7.2 Crude imports

Year	Quantity (mill.tonnes)	Value (Rs. Crores)
1990-91	20.699	6118.42
1991-92	23.994	7820.05
1992-93	29.247	10685.86
1993-94	30.822	10688.52
1994-95	27.349	10316.03
1995-96	27.342	11517.00
1996-97	33.906	18538.19
1997-98	34.494	15897.15
1998-99	39.808	14876.46
1999-00	45.01	30650.07

Empowered Standing Committee and the Oil Economy Budget

The ESC was constituted in 1987 and consists of chairman IOC, representatives of Ministry of Petroleum, representatives of Ministry of Finance, representatives of Ministry of Commerce, Director - Finance - IOC, ED-OCC is special invitee of this committee. Recently, the other oil companies namely HPCL and BPCL representatives, have been inducted as observer to this committee.

ESC is responsible for organizing imports of crude oil and petroleum products at best possible prices through bilateral approaches and through the process of tender subject to the condition that the quantity is as per the approval of the Government. ESC formulates its own guidelines for taking decision and IOC works as a secretariat to this committee.

All imports are finalised directly on a principal to principal basis. Unsolicited offers are not accepted, ESC meets as often as required. As mentioned before crude oil imports are guided by the OEB.

Strategy for import of crude oil

Until now crude oil purchases for the country as a whole have largely relied on term contracts. The gap between crude requirement and the amounts procured on term contracts either from domestic or international sources, has to be filled in by imports on spot basis. Generally as much as possible quantity requirement by refineries is tied up for import on spot basis. The strategy for crude oil imports broadly considers the following:

1. processing need of the refineries
2. security of supplies
3. economic evaluation of the crude oil based on yield pattern advised by OCC
4. diversification of sources
5. bilateral country to country relationships

Term contract

Term contracts are usually annual contracts finalised with the national oil companies of various oil producing countries within the quantity approved by the Government. Such imports are priced at the official selling price announced by these NOCs. Recently, term contracts are being entered into for 3 months period onward, both for crude oil and petroleum products depending upon demand etc.

Term contract for import of petroleum products, i.e. kerosene, diesel are entered into with NOCs having exportable surplus. Such imports are priced at prevailing market price at the time of delivery with a negotiated premium.

Term tender

Import of petroleum products and crude oil are also organised through of term tenders ranging for a period of 3 to 12 months through issuance of term tenders to parties registered in IOC's mailing list.

Imports on a spot basis

Quantity required over and above term supplies and domestic availability is imported on spot basis to cover for variation in production/demand and to import such grades of crude that are not available through term contracts. These are also organised through registered parties with IOC and by floating a tender of appropriate quantity with other necessary details. These are finalised on prevailing market prices.

The break-up of term and spot crude oil purchases since 1994-95 are give in the following table.

Table 7.3 Share of term and spot purchase

Year	Term* (%)	Spot (%)
1994-95	69	31
1995-96	75	25
1996-97	67	33
1997-98	66	34
1998-99 (P)	58	42

P: Provisional

*Term includes additional cargoes from term suppliers at official selling prices

The break-up of petroleum product purchases through term contract, term tender and monthly tender is given in the following table.

Table 7.4 Petroleum products purchase (% share)

Year	Term (%)	Term Tender	Monthly tender
1994-95	32	12	56
1995-96	28	9	63
1996-97	33	16	51
1997-98	38	35	27
1998-99 (P)	40	15	45

According to the Estimates Committee Report of 1998/99 purchase decision on term vs spot contracts is largely governed by the allowable flexibility of operation, the cost of acquisition of crude and bargaining power with the supplier.

To ensure that crude oil imports are made on cost effective basis, the MoPNG has taken the following steps:

1. A large share of requirements of imported crude is procured from the Middle East region which, given its proximity to our country, is cost effective.
2. Finalising the bulk of the imported crude oil requirement through term contracts with NOCs with pricing basis as per the official selling price. Term

- contracts with various countries ensure diversification of supply sources and provide security of supplies.
3. Uplifting additional cargoes from the term suppliers at their official selling prices, subject to such purchases being economical.
 4. Spot purchases are made on a competitive tender basis by inviting offers from registered parties.
 5. Continuous efforts are made to expand the basket of crude oils by including new grades found suitable in our refining system in order to increase competitiveness.

Oil imports – pricing mechanism

1. Term and spot import of oil are normally done at market price related formula.
2. For crude, price is generally linked to marker crude oil i.e. Oman, Dubai, Brent etc.
3. For products, price is generally linked to product prices in the main markets such as Arab Gulf, Singapore, Mediterranean etc.
4. Term prices for crude oil are linked to marker crudes and term prices for products are linked to product prices in the Arab Gulf market.
5. Contracts are linked to specific price over a period i.e. monthly average, first 15 days average of the month of loading, first 5 quotes of the month, 5 days after bill of lading or other price out period related to month of loading for crude oil. For products price out period are generally 5 days around bill of lading.
6. Evaluation is based on latest available spot prices published in Platts on the date of evaluation.

IOC floats tenders only to parties registered with it giving specific requirement of crude and time schedules. The parties are required to quote their prices within a fixed time frame. Offers from parties not registered with IOC are not entertained. The offers are evaluated by IOC and placed before the ESC for decision. The crude that provides the best netback is normally purchased and no negotiations are done with any party.

If the quantity available from seller 1 does not suffice, the balance quantity is purchased from seller 2 at the rate quoted by seller 2, and this process is continued till the full requirements are met. However, if the rates are found to be unreasonable, sometimes IOC has floated a tender again for the balance quantity. This system is transparent and IOC is able to get the optimum price under the prevailing circumstances.

Existing crude oil shipping policy

The existing shipping policy for crude oil and petroleum products in India has two most important facets:

- (1) All PSUs (with more than 51% government equity) are required to import crude and petroleum products on f.o.b basis. All exports of petroleum products will be on c&f basis. Exceptions are private companies like Reliance and joint sector companies like MRPL.
- (2) All shipping arrangements are centralised through Transchart.

Imports from Nigeria, however, have been on a c&f basis because of the longer haul. It is learnt that in October 2000, Government of India had finalised arrangements with the Government of Nigeria for import of 2 million tonnes of Nigerian crude (from October 2000 to September 2001 in 8 shipments) on fob basis. Some sellers sell crude oil only on c&f basis. In that case, imports could be arranged on c&f basis but only with the approval of the Ministry.

Freight charges

Till March 31, 1998, transportation costs of crude and petroleum products was reimbursed to Shipping Corporation of India (SCI) on a cost-plus basis. SCI was eligible to claim a predetermined percentage of profit over and above the operating costs incurred for carrying crude oil and petroleum products to India. With dismantling of the Administered Price Mechanism this cost plus regime was abolished with effect from April 1, 1998.

IOC was appointed the nodal agency for import of crude oil to India, while SCI was appointed by Ministry of Surface Transport as nodal agency for transportation of crude oil. The freight and charter hire rates as well as other related terms of crude transportation are covered in a Contract of Affreightment (COA) agreed between IOC (on behalf of oil industry) and SCI. These freight rates are market related (based on AFRA).

Advantages and disadvantages of the existing system

1. The existing system ensures that IOC is completely impartial in its supply and trading activity.
2. IOC is arranging supplies at optimal prices but the price may not be the best, as it cannot take advantage of the favourable opportunities in the market.
3. As the procedure followed by IOC is rigid, it often encounters operational problems.
4. It is generally believed that traders and oil companies are able to predict IOC method of tender purchase.

5. IOC does not use risk management tools.
6. IOC does not have flexibility to purchase on C&F basis, which may be commercially attractive sometimes.

So, it is evident that in the existing purchase procedure, the main disadvantage is that it is a tender on premium & thus has an in-built price risk of enormous proportion.

Keeping the above mentioned advantages and disadvantages of existing system in view, the Estimates Committee Report, 1998-99 recommends that the ratio of crude oil purchases through term and spot contracts should be rationalised to ensure (a) availing advantage from any decline in price of crude oil in the international market (b) security of supply.

Policy for crude oil exports from India

The current EXIM Policy stipulates that crude oil exports are canalised and can be exported through the canalising agency which at present is Indian Oil Corporation.

Also the producers under NELP are allowed to freely market their crude oil production in the domestic market only.

Implications of deregulation of crude oil imports and exports

Deregulation of imports

Government of India aims at complete deregulation of the oil industry by April 2002. Procurement of crude oil (domestic or imported) and selling of products will be entirely driven by market forces. IOC's role as the canalising agency for oil imports will cease to exist. Each PSU refinery will be required to prepare its own strategy for importing crudes.

Recently, the Government of India has permitted all oil companies to source their crude oil requirements independently. Public sector refineries would need to devise their own strategy for

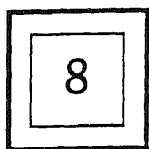
- types of crude oils that need to be refined, in light of the refinery configuration and other techno-economic considerations
- sourcing of the crude oils
- shipping arrangements

The government is initiating steps to allow oil companies to enter into commodity futures to hedge against price risks while importing crude oil and petroleum products.

In light of the above, ONGC may be approached by many domestic refining companies to tie up long term requirements, to the largest extent possible. The attractiveness of the domestic market for ONGC and the negotiating advantages/disadvantages will be discussed further in the subsequent report.

Deregulation of exports

Under the current policy, crude oil exports are canalised through IOC. For the purpose of this study we assume that ONGC will not be able to export its crude oil freely at its own discretion.



Approach towards marketing strategy

With the dismantling of Administrative Price Mechanism ONGC is expected to be at freedom to enter into long term contract for supply of its crude to the domestic refineries at import parity price. Presently ONGC is being paid only international FOB price for similar quality crude traded in the international market. However, the domestic refineries are paying to OCC import parity price for this crude. The difference between the FOB price and C&F price of crude is being mopped up by Oil Coordination Committee for balancing the various transactions in the oil pool account.

In pursuance of the decision of 1997 regarding dismantling of APM refineries are allowed to source crude of their requirement. To survive in the competitive environment, the refineries are likely to adopt various strategies to reduce their cost of production. One of the major areas where all efforts will be focused would be the procurement cost of crude oil. All innovative strategies would be evolved by the refineries to source the crude of their choice at the lowest price. Some of the refineries are under compulsion due to environment regulation, to use only sweet crude up to a certain percentage so that the emission standards are within norms. Thus these refineries would like to continue to use Bombay High crude provided, prices of these crude are in line with the international marketing trend and developments.

According to the existing Export-Import policy ONGC may not be in a position to export crude oil easily because of infrastructure constraints & also canalisation role still continue to be with IOC. Even if these constraints are tide over by ONGC, ONGC is not likely to get price better than the FOB price. This fact is known to most of the refineries and therefore they may be expecting that ONGC is not likely to enter international market for export of its crude.

As discussed earlier in Chapter 5, there is an increasing dependency on imports of crude for meeting the requirement of the refineries. In view of this Government of India may not easily permit ONGC to export crude to other countries. Furthermore, due to the emerging critical situation prevail in Middle East & neighboring Afghanistan, oil security for the country assumes considerable importance, National Security may dominate economic factors for allowing export of this crude outside the country.

Therefore though ONGC may be expecting to move towards import parity prices while fixing its price for crude from April '02, it will not be easy for it to convince the refinery. Similarly refinery may not be justifying in insisting that they will not pay more than what ONGC is presently getting from the OCC. Because ONGC will be committed to pay certain liabilities to the Government of India under various rule out of the amount which they get from refineries. The various options that have been examined are:

Option A. ONGC receives fob of a comparable international crude and pays central sales tax.

Option B. ONGC receives fob of a comparable international crude but does not pay central sales tax

Option C. ONGC receives import parity price of a comparable international crude and does not pay central sales tax

Option D. ONGC receives import parity price of a comparable international crude and pays central sales tax.

Clearly, Option A is the worst option for ONGC while Option C is best case. However, the final negotiated price may lie somewhere between these options. The avoided cost of importing if the crude is priced at FOB may be shared between the refinery and ONGC in some proportion depending on the negotiating power of each.

One more factor requires settlement is the custody transfer point since that will determine as to who will bear the cost of transportation of crude to the refinery.

Over and above the central sales tax, ONGC has to pay royalty, cess and corporate taxes to the government. Netting out all the payments and cost of production of ONGC which according to ONGC officials average around \$9/bbl, leaves the surplus for ONGC which will be available to meet its investment commitments in exploration and production. This surplus has been calculated field wise and is detailed in subsequent chapters. ONGC will invest Rs 47590 million in various IOR/EOR schemes and expects to increase the reserves by 61.53 million tonnes in 20 years. This works out to \$ 2.3/bbl. In comparison, the investments in exploration of other oil companies in Asia-Pacific region for 2000/01 are given in Annexure 8.1.

ONGC not only has to negotiate with the refineries on whether it should receive fob or import parity price for its crude, but also has to negotiate premiums on the base price so as to increase its surplus. The premiums that ONGC crudes can command depend on the negotiating powers of ONGC vis-à-

vis customers. The basis on which ONGC crudes can command a premium or will be discounted is briefly discussed below.

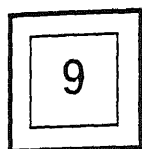
Discounts/Premiums over the base price

Advantages and disadvantages of ONGC vis-a-vis refineries, which will dictate its negotiation power, have been assessed on the following grounds:

1. crude oil quality
2. supply infrastructure to domestic refinery
3. position of field (landlocked or coastal)
4. alternative options for refineries and ONGC
5. security of supplies (taking in imported vis-à-vis domestic crude)
6. exchange rate risks in importing larger amounts of crudes
7. international oil market uncertainties
8. infrastructural constraints in importing more crude oil

Most of these factors have been quantified and culminate into assessing the net discount or premium on the base price of a ONGC crude. However certain advantages and disadvantages are qualitative in nature. These can be dealt at the best across negotiation tables with the potential customer.

Hence our analysis is essentially a negotiating brief for ONGC, which will also serve as a roadmap for ONGC informing it about its' negotiating partner's as well as its' own strengths and weaknesses. Each of the ONGC fields has been analysed separately and a marketing strategy framed for each crude while outlining a possible overall organisational strategy.



Strategy for marketing Bombay High crude

This chapter outlines the various considerations that would determine the potential price of Bombay High (BH) crude.

According to the current policy scenario, ONGC may not be able to export its crude and consequently would have to explore a strategy to get the best prices in the domestic market. Also, as shown in Chapter 6, the tenth plan envisages a growing import dependence and also growing demand for sweet crude, implying that the domestic market provides ample opportunity to ONGC to sell its crude. In this context, not only the existing customer base of ONGC assumes significance, but also potential new customers. The off takes of Bombay High crude by refineries in India is summarized below.

Table 9.1 Refinery wise consumption of BH crude('000 tonnes) 2000/1

Refinery	Total thrupt	BH thrupt
Existing customers		
HPCL-Mumbai	5575	2165
BPCL-Mumbai	8664	5919
Koyali-Gujarat	12005	832
Kochi	7520	3180
Chennai	6046	1261
CBU-Narimanam	579	9
Mathura	7134	1555
Panipat	5708	90
Total	53231	15011
Potential Customers		
Reliance	25716	-
Mangalore	6438	-
Vizag	6407	-

*Source: Oil Cordination Committee (OCC)

** Capacity

The bulk of BH crude (about 11 MMT) is consumed by the refineries at Mumbai and Kochi. Given the proximity of these refineries to the BH field they are expected to continue to procure the BH crude in future too.

Currently, MRPL runs entirely on imported crudes and consumes about 0.4 MMT of African crudes (to which BH crude has similar characteristics). However, given that Mangalore is already importing over 6 MMT of crude, it will not entail any considerable effort or risk to import that 0.4 MMT.

The Bhatinda and Bina refineries are far moved from the BH fields and also the dates of their commissioning is uncertain. Hence these refineries have not been considered in our analysis as potential customers.

The Reliance refinery at Jamnagar also imports all its crude requirement at present and ONGC has to negotiate with Reliance on same terms as with other customers. However, the average imported crude procurement cost of Reliance in 2000 was about \$23/bbl (Annual Report of Reliance Petroleum Limited, 2001) as against an average of \$29.60/bbl for the existing customers of BH crude. ONGC has to keep this in mind while considering Reliance as a potential customer for BH crude. Reliance may not pay high prices for crudes as it is well equipped to process low quality crudes procured at cheap prices.

The Vizag refinery of HPCL is presently using crude from the Ravva fields operated by the Cairns Energy consortium. The price paid for it is fob Arab Light plus 60 cents which amounts to \$20.3/bbl (as of January 2002). Though the joint venture is demanding that its crude is of comparable quality to those of the Far East market and its price should be linked to an average of Tapis and Minas, the case is in arbitration and is awaiting decision. HPCL being the government nominee through which Ravva crude has to be sold, it is unlikely that Vizag refinery will replace Ravva with BH crude when Ravva will be a cheaper option. However, BH can replace the imported crude from Africa by Vizag which amounted to 1.84 MMT in 2001.

The BH crude production profile, as per ONGC estimates, is shown in Table below.

Table 9.2 Projected production of Bombay High crude (million tonnes)

	Current	2002-03	2003-04	2004-05	2005-06	2006-07
Production	15.01*	15.293	15.376	16 085	15.981	15 592

consumption of BH crude by refineries

This shows a stagnating production trend. Thus if ONGC can maintain its existing customers, with whom ONGC has already established supply links, it may not have to negotiate with new customers.

Basic price

The pricing options have been discussed in Chapter 8 and are reproduced below.

Option A. ONGC receives fob of a comparable international crude and pays central sales tax to the government.

Option B. ONGC receives fob of a comparable international crude but does not pay central sales tax

Option C. ONGC receives import parity price of a comparable international crude and does not pay central sales tax

Option D. ONGC receives import parity price of a comparable international crude and pays central sales tax.

Evaluating the options for ONGC

The detailed calculations for BH crude, evaluating the price base under each option is given in Annexures – 9.1 to 9.9.

Options C and D show the import parity price of BH, benchmarked to a equal mix of Bonny Light and Escarvos, at the custody transfer point Uran.

It shows that the difference between the basic price under Option A (the worst option) and the Option C (the best option) is Rs 1591.92/MT or \$ 4.72/bbl. This then represents the margin in negotiations, sharing of which will depend on the negotiating power of the parties involved.

Premium factors for ONGC

Security of supply

Unforeseen emergencies like war or natural calamities have disrupted crude oil production and supply in the past. Greater dependence of refineries on imported crudes may entail risks of supply disruptions. In such situation, refineries will have to operate at a lower capacity. This would increase the fixed cost per tonne, adversely affecting the refinery margins. For existing buyers, replacing BH crude with imported crude will mean an additional exposure to such risks and ONGC can command a premium for that while for potential customers it would mean reduction in such risks.

Annexure 9.10 lists the major disruptions in crude oil supply from major producing countries and the concurrent drop in supply. The average reduction in global supplies during Middle East crisis in 1980 and 1990 had been 3.8 mb/d and had lasted for a average period of 120 days making the overall reduction in supply as 62.21 MMT. The share of India in world oil imports is about 3.5%. If it is assumed that reduction of supply to India will be in the same proportion of the total global supply reduction, about 2.1 MMT of supplies will be unavailable to Indian refineries. Translating the curtailment across the board and assessing its impact on lower crude runs and hence higher fixed costs is taken in this exercise as a possible indicator for security of supplies.

The increase in fixed costs per tonne in case of crude supply disruptions and lower refining capacity utilisation is shown below. The detailed calculations are provided in Annexure 9.11.

Table 9.3 Increase in fixed refining costs

Refinery	Rs/MT	\$/bbl
<i>Existing customers</i>		
BPCL	6	0.017
HPCL	3	0.010
Kochi	10	0.031
Chennai	9	0.028
Mathura	4	0.011
Panipat	9	0.028
Koyali	2	0.007
<i>Potential customers</i>		
Mangalore	10	0.029
Vizag	1	0.003

The premium for potential customers has been calculated assuming that they would replace entire imported crude throughput with BH crude.

ONGC could command a average premium of \$0.029/bbl, since supplies from it are relatively assured vis-à-vis the imports of a refinery. However, refineries, which are less dependent on BH, may not be inclined to pay a premium for securing supplies from ONGC.

Use of existing infrastructure

As mentioned in Chapter 7 crude from Bombay High is collected at the Uran CTF and supplied to HPCL and BPCL refineries by ONGC owned and operated pipelines. For refineries in Koyali, Mathura and Panipat, BH crude is shipped to Vadinar and fed into the Salaya-Mathura Pipeline. The SBMs at Vadinar and SMPL are owned by IOC. Crude for Kochi, Chennai and Vizag refineries is shipped from Jawahar Deep to the respective ports in these places.

The refineries in Mumbai pay a tariff of Rs 37/MT for transporting the crude from the CTF. These pipelines were laid in 1978, and have an average balance life of eight years, assuming a pipeline age of 30 years. The pipeline tariff for the same in the deregulated scenario is likely to go up to Rs 87.66/MT, as per recommendations made by the ETG. This increase notwithstanding, it may be worthwhile for ONGC to investigate further the case for retaining these assets in comparison to transferring these pipelines to the refineries, keeping in context the expenses involved in operating and maintaining them, as also issues related to pipeline losses. Such a move may also provide a captive link with these

two refineries, and hence an assured offtake of 8 MMT from its total production of 15 MMT.

If the pipeline is retained by ONGC, then the costs of transportation is an added factor that has to be negotiated between HPCL/BPCL and ONGC.

As for refineries in the North and South of the country, crude is moved by ships, and the facilities at the ports to handle this are not owned by ONGC. This may weaken the case for BH, in the event these refineries decide to replace BH with imported crude, as there are no captive infrastructural links forcing the refineries to take BH crude.

Port facilities augmentation for higher imports

In the event that the refineries argue that they can replace all their crude intake from BH by augmenting imports ONGC may not be able to counter it by citing higher costs to augment port handling facilities. This is the case because to the extent BH does not land at these ports, the spare capacity could be diverted for higher imports. But a problem one can foresee with this arrangement relates to a likely increase in demurrage on account of unloading of bigger or a higher number of crude parcels arriving at the port.

Greater imports, to replace the domestic crudes, could imply greater traffic congestion at ports and hence demurrage expenses. The oil handling capacity and utilisation of ports at which the concerned refineries import crudes are shown in Table 9.4 below.

Table 9.4 Crude handling capacity at ports

Port	Type of berth (No)	Draft (mtrs)	Length (mtrs)	Maximum size of ships (DWT)	% occupancy	
					1998-99	1999-00
Mumbai	Pirpau Oil Pier (1)	7.50	174	35000	14	28
	New Pirpau Pier (1)	12.00	197	47000	74	67
Cochin	Oil terminal (1)	11.70	250	86000	64	97
Chennai	Liquid bulk (2)	16 - 17.4	304, 338.94	140000	77, 69	60, 60
Vadinar	SBM (2)			No restriction	49	54
Vizag	Liquid Bulk (1)	10.1	183	36000	76	83
	Liquid Bulk (2)	9.8	183	36000	82	78
Mangalore	Oil jetty (1)	10.5	330	30000	64	67
	MRPL crude jetty	13	320	85000	60	60

Source. Basic Port Statistics of India 1999-2000

Vadinar, at which imports for Koyali, Mathura and Panipat refineries land has sufficient capacity to cater to greater imports. Hence demurrage from these refineries have been considered as nil. However the % occupancy of Pirpau,

Cochin and Chennai ports are high and may entail large demurrage costs in case of greater imports.

Considering cargoes from Nigeria in October 2000 to May 2001, the average demurrage at West Coast India and East Coast India has been Rs 9.72 /MT and Rs 9.52 /MT, respectively. The detailed calculations are at Annexure 9.12. To this extent ONGC can ask for a premium on Bombay High for avoided demurrage.

Costs of international Procurement

As mentioned earlier there are costs associated with procuring crude internationally, ranging from scanning the market and suppliers, issuing and evaluating tenders, arranging for ships, foreign exchange, letters of credit. Until now IOC was the sole canalising agency importing crude on behalf of other companies. However, in a deregulated scenario companies would prefer to make their own arrangements as evidenced by recent progress made by HPCL and BPCL in signing long term contracts. However, to the extent they can be assured of domestic crude availability as per their quantitative and qualitative requirements, they can limit the costs associated with international purchases.

While an attempt has not been made to quantify all the above costs, some tangibles such as costs related to opening a letter of credit, exchange rate risks, and freight diseconomies associated with smaller parcels have been highlighted below. These provide negotiating advantage to ONGC for a premium on the base price.

Letter of credit

The treatment of LC charges while working out import parity formula to price crude and products has varied over time. The Oil Prices Committee, 1976, recommended a flat LC charge of Rs 1/MT while the Oil Cost Review Committee, 1984, adopted a stand that the LC charges should be compensated separately and hence was not included in its recommended price buildup. However, currently, the Oil Coordination Committee uses the norm of 0.3% on cost & freight for determining the LC charges payable by the refinery.

The level of LC charges depends on the creditworthiness of the buyer. IOC, being a fortune 500 company, may be paying a lower LC charge while any standalone refinery, importing crude independently for the first time, may be required to pay a higher LC charge.

The table below shows the increase in the cost of crude imports on account of 0.1 percentage point increase in LC charges.

Table 9.5 LC Charges

Refinery	Rs/MT	\$/bbl
Existing customers		
BPCL/HPCL	7.35	0.021
Kochi	7.32	0.021
Chennai	7.35	0.021
Mathura	-	-
Panipat	-	-
Koyali	-	-
Potential Customers		
Vizag	7.39	0.021
Mangalore	7.33	0.021

To the above extent, ONGC could ask for a premium for relative ease in procuring domestic crude supplies.

Foreign exchange risk

Refineries need to factor in foreign exchange risks for crude oil imports. There could be two types of risks that they could be exposed to.

a) The FOB value (in USD) of the crude oil is converted into rupee terms at the actual telegraphic transfer rate of exchange as obtaining on the date of remittance^a.

Thus, since the imports are in dollar denominations, there is a substantial exchange rate risk involved in the process as the rupee can depreciate^b very quickly which will increase the crude cost. However, for domestic crude, since the payment would be rupees, such risks do not apply.

For instance a 1% depreciation of the rupee will increase the cost of importing from the base case, as shown below.

^a Oil Prices Committee, 1976, Chapter XIII, Page 100

^b During 1999-00, the rupee depreciated by about 2.9% from the annual average of Rs. 42.07 per US dollar in 1998-99 to Rs. 43.33 in 1999-00 (Economic Survey, 2000-01). The depreciation was steeper in 2000, by end of January 2001, the rupee had depreciated by 6.1% from March 2000. This can have considerable bearing on cost of importing crudes.

Table 9.6 Exchange rate risks

Refinery	Rs/MT	\$/bbl
Existing Customers		
BPCL/HPCL	81.66	0.242
Kochi	81.30	0.241
Chennai	81.74	0.242
Mathura	82.14	0.243
Panipat	81.74	0.242
Koyali	81.74	0.242
Potential Customers		
Vizag	82.03	0.243
Mangalore	81.48	0.241

ONGC could use the above argument to build a premium on its base price.

b) Another type of risk that the refineries could be exposed to is the impact of changes in exchange rate between the time it buys foreign currency to pay for its purchases, and the time the actual delivery takes place, assuming no hedging has been resorted to cover the exchange rate fluctuation risk.

Freight diseconomies

Presently, the imported crude oil requirements of the coastal refineries like HPCL and BPCL is taken care by IOC, which brings crude at Vadinar in large tankers from where it is distributed domestically. However with deregulation, refineries importing independently may have to import in smaller vessels that will increase freight expenses, unless they continue with the present arrangements with IOC, or if BPCL, HPCL try to synchronise their international purchases and use common shipping arrangements. Port capacity constraints may also force the refineries to import crude in smaller tankers (see table 9.3). Thus replacement of domestic crude with imports may prove costlier.

The worldscale (WS) rates for crude oil imports to India from Nigeria during the year 2001 have been tabulated below.

Table 9.7 Freight rates for crude imports from Nigeria in 2001 (as per Worldscale 100)

Loadport	Rates to Indian ports (\$/MT)					
	Vadinar	Mumbai	Cochin	Chennai	Vizag	Mangalore
Bonny Offshore Terminal	13.20	13.06	12.45	13.21	13.68	12.75

AFRA assessments for February 2001 for LR II and VLCC are 150WS and 116.9 WS respectively. This reveals that the freight rates for LR II will be about 30% higher than for VLCC at the same WS which clearly shows the advantage in bringing in larger vessels. Thus, increase in cost of crude imports on account of importing in LR-II as compared to VLCC for select refineries, is as follows:

Table 9.8 Freight diseconomies

Refinery	Rs/MT	\$/bbl
Existing Customers		
BPCL/HPCL	220 53	0 654
Kochi	210 49	0 624
Chennai	223 32	0 662
Mathura	-	-
Panipat	-	-
Koyali	-	-
Potential Customers		
Vizag	231 01	0 685
Mangalore	215 56	0.639

However, the combined requirement of imported crudes by the three IOC refineries in the north-western region is 16.69 MMTPA. The maximum capacity of a VLCC tanker is 0.319 MMT. Thus, IOC can sustain a vessel size of VLCC for its imported crude requirement and hence cannot be expected to pay a premium on the account of bringing crude on a smaller vessel.

An addition of this extent to the cost of imported crude, could be used by ONGC to argue for a premium on supplying its crude.

Discount factors for ONGC

In the deregulated scenario, the refineries paying the price on international parity will demand an international quality crude. However, the BS&W of BH crude, at 0.1%, is higher than the international standard of 0.02%, above which the crude is discounted. Thus, BH crude is also likely to be discounted on this account.

As provided by ONGC, it costs about Rs. 100 million to desalt 1 MMT of crude. Thus, either ONGC has to treat the crude to bring it to the international standard or negotiate a discount for quality, with the refineries. The current sale of BH crude is about 15 MMT. Desalting of this crude would cost around Rs. 1500 million according to estimates provided by ONGC. The annutised capital cost is estimated at 16.47 Rs/MT. It would add to the cost of production and impact the margin ONGC could make on crude sales. The detailed calculations are given in Annexure 9.13. Alternatively, the cost may be taken as the discount ONGC may have to offer to refineries for the high BS&W content.

Summary table

Table 9.9 Summary of premiums and discount

	Unit	BPCL	HPCL	Existing Customers					Potential Customers	
				Chennai	Kochi	Mathura	Panipat	Koyali	Vizag	Mangalore
Premium factors for ONGC										
Security of supplies	Rs/MT	6	3	9	10	4	9	2	1	10
Demurrage charges	Rs/MT	9.72	9.72	9.52	9.72	0	0	0	9.52	9.72
LC Charges	Rs/MT	7.35	7.35	7.35	7.32	0	0	0	7.39	7.33
Exchange rate risks	Rs/MT	81.66	81.66	81.74	81.3	82.14	81.74	81.74	82.03	81.48
Freight diseconomies	Rs/MT	220.53	220.53	223.32	209.21	0	0	0	231.01	215.56
Total Premium	Rs/MT	325.26	322.26	330.93	317.55	86.14	90.74	83.74	330.95	324.09
Discount factors for ONGC										
BS&W problem	Rs/MT	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47
Total Discount	Rs/MT	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47	16.47
Average Net Premium	Rs/MT	308.79	305.79	314.46	301.08	69.67	74.27	67.27	314.48	307.62
Average Net Premium	\$/bbl	0.916	0.907	0.933	0.893	0.207	0.220	0.200	0.933	0.917

Strategic option

As the above analysis shows, BH crude is in a position to command a premium over and above the basic price from all the refineries. Applying this premium to all the four options for basic price for BH crude yields the following surplus for ONGC. The detailed calculations are from Annexure 9.1 to 9.9.

Table 9.10 Surplus for ONGC (\$/bbl)

Refinery	Option A	Option B	Option C	Option D
BPCL - Mumbai	1.86	2.37	5.44	4.81
HPCL - Mumbai	1.86	2.37	5.44	4.82
Koyali	1.40	1.91	4.98	4.34
Mathura	1.40	1.91	4.98	4.35
Panipat	1.41	1.92	4.99	4.36
Kochi	1.85	2.36	5.43	4.80
Vizag	1.88	2.38	5.45	4.82
MRPL	1.86	2.37	5.44	4.81
Chennai	1.88	2.38	5.45	4.82

Given the ONGC's exploration commitment of \$2.3/bbl, it seems that ONGC should negotiate for Option C. However it should accept no less than Option D which means that it should get the import parity price for BH and may pay the sales tax on behalf of the refineries.

Strategy for marketing North and South Gujarat crudes

This chapter outlines the various considerations that would govern the potential price of Gujarat crudes.

Koyali is the only refinery that processes North and South Gujarat crudes. To the extent that ONGC has no alternate infrastructure to supply these crudes to any other refinery, either in India or abroad, ONGC is likely to continue to be dependent on Koyali refinery for Gujarat crudes.

Koyali takes about 5.5 million tonnes of imported crudes via the Salaya-Mathura pipeline, owned and operated by IOC. However, the capacity of this pipeline is almost completely utilised, and hence Koyali is also a captive buyer for ONGC, at least till the time the capacity of the pipeline is enhanced for the entire throughput of the refinery.

Reliance's Jamnagar refinery is the only other operating refinery in the region and hence can theoretically take the Gujarat crudes. However, the average procurement cost for Reliance for the year 2000/01 was \$23.18/bbl (Annual Report of Reliance Petroleum Limited, 2001) which is lower than Koyali refinery's \$29.64/bbl. This is because of the Reliance refinery's ability to process the low quality crudes available at cheapest prices. This point has to be kept in mind while negotiating with the refineries.

Gujarat fields have been projected to have a stagnant production for the 10th five-year plan period, as shown in the table below.

Table 10.1 Projected production from Gujarat fields (MMT)

	2002-03	2003-04	2004-05	2005-06	2006-07
Mehsana	2.337	2.522	2.637	2.886	2.979
Ahmedabad	1.473	1.504	1.477	1.438	1.392
North Gujarat	3.81	4.026	4.114	4.324	4.371
Ankleshwer	2.09	1.949	1.749	1.538	1.357
Cambay	0.1	0.1	0.1	0.1	0.1
South Gujarat	2.19	2.049	1.849	1.638	1.457
Total	6.00	6.075	5.963	5.962	5.828

Source. ONGC

Thus, if ONGC can maintain the existing supply relationship with the Koyali refinery, it may not need to look for alternate buyers.

The specific linkages of the ONGC fields to the Koyali refinery will play an important role in the overall marketing strategy. A few salient features are-

1. The supply pipelines were installed nearly thirty years back and may need replacement in a few years.
2. The supply infrastructure is completely owned and maintained by ONGC.
3. The ONGC fields are the nearest source of crude for the Koyali refinery.
4. The Vadinar-Koyali section of the Salaya-Mathura pipeline is almost completely utilised.
5. The only other existing refinery in the region, Reliance, does not have the infrastructure to move ONGC's crude to its location.

Basic price

As elaborated in chapter 10, there are four options ONGC faces while negotiating the basic price of the crude. These are reproduced here.

- ♦ **Option A** – Price the crude at FOB of the benchmarked crude at custody transfer point but pay the sales tax on the crude.
- ♦ **Option B** – Price the crude at FOB of the benchmarked crude at custody transfer point.
- ♦ **Option C** – Price the crude at the Import Parity Price (IPP) of the benchmarked crude at the custody transfer point.
- ♦ **Option D** – Price the crude at the IPP of the benchmarked crude at the custody transfer point but pay the sales tax on crude.

Option A is the worst option while Option C is the best case. The detail calculations of these options are at Annexure 10.1.

As the tables in Annexure 10.1 show, the difference between Option A and Option C is Rs 1601.56/MT or 4.749 \$/bbl.

Among the many other things that have to be negotiated between Koyali and ONGC, one is cost of transporting the crude from Vadinar to respective CTFs in North and South Gujarat. Ideally, if the pricing is done on import parity basis, these costs should be borne by the refinery if the custody transfer point are the CTFs.

However, the import parity have been calculated at Vadinar and not at respective CTFs because the imported crudes for the refinery land at Vadinar and the refinery may not pay anything more than the landed cost of imported crude at Vadinar since it has its own pipeline from Vadinar to Koyali.

The methodology detailed in Chapter 10 is followed here. First the possible reasons for premiums or discount are discussed and then the final price

recommended keeping in mind the \$ 2.3/bbl exploration commitment by ONGC.

Premium factors for ONGC

Security of supplies

As elaborated in Chapter 10, there is always a risk of disruption in supplies attached with crude imports since the major crude export originate from politically sensitive areas. Thus, increasing the import dependency will entail extra risks of supplies for a refinery. The risk of disruption is relatively lower for the domestic crudes.

The increase in fixed cost per tonne on account of lower capacity utilisation due to disruption in supplies for Koyali refinery for North and South Gujarat crudes is shown below. The detailed calculations are at Annexure 10.2.

Table 10.2 Increase in fixed cost

Refinery	Rs/MT	\$/bbl
North Gujarat	3.868	0.011
South Gujarat	3.441	0.010

Thus, ONGC is in a position to command an average premium of \$0.109/bbl for its supplies being more secured than imported crudes. However, Reliance is currently importing its entire crude requirement and a quantity of 5.5 MMT is too small to change the risk profile of 25.716 MMT of crude portfolio.

Existing infrastructure

One crucial factor in negotiations will be existing infrastructure at the disposal of both refinery and ONGC. ONGC owns the supply pipelines moving crude from its Central Tank Farms in North and South Gujarat to the Koyali refinery. Koyali imports around 5.5 MMT of crude via Salaya-Mathura pipeline (SMPL). If the capacity of SMPL is enhanced or a new pipeline is laid with enhanced capacity, this would mean that Koyali would have an edge over ONGC in negotiations. On the other hand, if the status quo is maintained, Koyali will be at relative disadvantage since it will be dependent on Gujarat crudes to run its refinery at maximum utilisation.

The domestic crude supply pipelines are nearing their economic life and may have to be replaced shortly. In such a scenario, the question arises as to who should replace the pipelines.

In view of the fact that Koyali refinery expansion has been put on hold (The Economic Times, 12th February, 2002) and thus the possibility of capacity expansion of SMPL (or at least the Viramgam-Koyali) section of the pipeline is remote, these pipelines can be transferred to the refinery as this would avoid all the claims and cost for ONGC regarding quantity differences, pilferage and theft and eventually replacement.

Augmentation of facilities for higher imports

Imported crude for the IOC refineries in the northwestern region are received at an offshore SBM off the coast of Vadinar. This SBM has no capacity constraints and the occupancy has also not been high (Table 9.5). This means that importing an additional quantity of 5.5 MMT is unlikely to cause any additional expenses for IOC.

However, the capacity of the SMPL pipeline is completely utilised and cannot support extra imports of 5.5 MMTPA. This means that to replace Gujarat crudes by imported crudes, IOC will have to augment the capacity of SMPL. By thumbrule estimates, it costs around Rs 0.1 million per inch diameter per kilometer to install a crude pipeline. Taking this estimate, it will cost around Rs 745.2 million to set up a new pipeline of 18" from Vadinar to Koyali which would yield an annutised capital cost of Rs 17.17/MT. Thus, ONGC can command a premium to this extent on the account of avoided cost of augmenting the facilities for extra imports. The detailed calculations are at Annexure 10.3.

Again, Reliance imports its entire throughput of crude and hence does not need to augment any import infrastructure. Thus, it will not pay any premium on this account.

Costs of international procurement

As detailed in Chapter 10, there are certain costs which have to be incurred during the procurement of international crude. Thus, the refineries taking domestic crude will be avoiding all these additional costs of imports. While it is not possible to quantify all the costs involved in the procurement process, three important and most tangible have been highlighted.

Letter of credit

As mentioned in Chapter 10, the letter of credit charges for importing crude vary from buyer to buyer. IOC being a Fortune 500 company and because of the fact that it has been importing crude for many years would not be required to pay an

extra LC charge. Thus, this factor will not enable ONGC to command a premium.

Foreign exchange risk

As elaborated in Chapter 10, since imports are on dollar basis, there is a considerable foreign exchange risk involved, assuming that refineries are not hedging for this risk. The risk is essentially the increase in the fob price of crude, expressed in rupee terms, due to depreciation of rupee, which makes the final price higher than expected. For instance, a 1% depreciation in rupee will raise the import cost of an equivalent quality crude for Koyali refinery by Rs 81.87/MT (\$0.242/bbl). Thus, ONGC can build up a premium on its base price on this account.

Freight Diseconomies

The combined requirement of imported crudes by the three IOC refineries in the North-Western region is 16.69 MMTPA. The maximum capacity of a VLCC tanker is 319,000 MT. Thus, IOC can sustain a vessel size of VLCC for its imported crude requirement and hence cannot be expected to pay a premium on the account of bringing crude on a smaller vessel.

However, there are certain factors that will force ONGC to yield a discount on the following account.

Discount factors for ONGC

Quality of ONGC crudes

The BS&W content in the North and South Gujarat crudes is 0.3% and 0.5% respectively. This is higher than the internationally accepted range of 0.02-0.2% of BS&W. If ONGC aims to get internationally competitive price in a deregulated scenario, it will have to meet the international quality also. Thus, it would have to reduce the BS&W content in its crudes. A desalter plant at Kalol is already desalting the North Gujarat but additional costs may have to be incurred for the same for South Gujarat crude. According to estimates given by ONGC, it costs around Rs 100 million to desalt 1 MMT of crude which gives an annutised capital cost of Rs 22.3/MT for desalting the 2.3 million tonnes of South Gujarat crude. The detailed calculations are at Annexure 10.4.

No alternative for ONGC

Even if ONGC were allowed to export the crude, the lack of supporting infrastructure would have prevented ONGC from doing so. The only other refinery that can possibly move ONGC crudes is the Reliance's Jamnagar refinery. But there is no infrastructure to move the crude from ONGC's CTFs in North and South Gujarat to the Reliance's refinery.

Reliance refinery has the ability to process the cheapest crude. So it would not pay to ONGC anything above its average procurement cost. Thus, cost of transporting the crude from North and South Gujarat to Jamnagar will reduce the realisation to ONGC.

As per the ETG recommendations, the tariff for new crude pipeline comes out to be Rs 1.23/MT/Km^a. The average distance from Nawagam and Ankleshwar to Jamnagar is 311 and 484 kms respectively. Thus the cost of transportation is estimated as Rs 382.53/MT and Rs 595.32/MT respectively. These can be taken as the discount that ONGC may have to yield to Koyali.

Summary table

Table 10.3 Summary table

	Rs/MT	\$/bbl
Premium factors for ONGC		
Security of supplies		
a) North Gujarat crude	3 868	0 011
b) South Gujarat crude	3 441	0 010
Augmentation of facilities for imports	17.17	0 051
Cost of international procurement		
Exchange rate risks	81.87	0 243
Total		
a) North Gujarat crude	102 908	0 305
b) South Gujarat crude	102 481	0 304
Discount factors for ONGC		
Inferior quality crude		
a) North Gujarat crude*	-	-
b) South Gujarat crude	22.3	0 066
No alternative for ONGC		
a) North Gujarat crude	382.53	1 134
b) South Gujarat crude	595.32	1 766
Total		
a) North Gujarat crude	382.53	1.134
b) South Gujarat crude	617.62	1 832
Net discount		
a) North Gujarat crude	279 622	0 829
b) South Gujarat crude	515.139	1 528
Average Discount	375 165	1 112

* This does not take into account the fact that North Gujarat crude is highly acidic and hence ONGC will have to give a discount on this account also which may be negotiated with the refinery

^a The ETG gives the pipeline tariff as Rs 1.13/MT/KM. Escalating it by 80% of the WPI index for each year after 1999-00, we have the tariff as Rs 1.23/MT/KM

Strategic option

As the above analysis show, ONGC will probably have to give a discount to Koyali refinery for its North and South Gujarat crudes. Applying this discount to all the four options and deducting the various charges ONGC will have to pay, the following surpluses emerge.

Table 10.4 Surplus for ONGC (\$/bbl)

Refinery	Option A	Option B	Option C	Option D
Koyali	0.57	1.08	4.17	3.53

As this table shows, Option A and Option B are not sustainable for ONGC.

Under Option D, given the exploration commitment of 2.3 \$/bbl, the net left is \$1.23/bbl which gives 34.8% return to ONGC which is very fair. Thus, ONGC should not accept anything less than Option D.

This chapter outlines the various considerations that are important in determining the price of Cauvery basin crude.

With production volume of 0.431 MMT, the Cauvery basin crude is not processed by many refineries. The CBU refinery of Chennai Petroleum Corporation (CPCL) takes the entire Cauvery basin crude. Other refineries in this region are CPCL Chennai, KRL Kochi and HPCL Vizag. However, since CPCL owns both Chennai and CBU refineries, it can be assumed that Chennai refinery would not compete with CBU refinery for this crude. Moreover, given the policy restriction along with small production quantity, it can be assumed that this crude will not be exported.

The production from the Cauvery Basin is projected to decline in the coming years as shown below.

Table 11.1 Projected production from Cauvery field (MMT)

	2002-03	2003-04	2004-05	2005-06	2006-07
Cauvery	0.307	0.295	0.243	0.201	0.17

Source. ONGC

This means that the possibility of this crude being processed by any other refinery is remote since no one would like to enter into a purchase contract for a declining field.

There are two other refineries in the region – Kochi and Vizag. But it will be difficult to term these as prospective buyers due to two main reasons.

Firstly, Vizag refinery does not process Arab Light crude to which the Cauvery crude has been benchmarked. Since no assumption can be made regarding the refinery configuration, it cannot be assumed that the refinery will be able to process the Cauvery crude.

Secondly, the cost of transporting the Cauvery basin crude to the Vizag and Kochi refinery will be prohibitive. The crude would first have to be moved to Chennai from where it will have to be transported via sea route to Kochi refinery and perhaps via road to Suryasayanam from where it will be pumped to Vizag through the existing pipeline. Infact, the cost of transporting even the KG crude to the Vizag refinery were prohibitive enough for ONGC to commission its own

small refinery at Rajahmundry to process the KG crude. Thus, it can be assumed that Cauvery basin crude cannot be moved to any refinery except CBU.

On the other hand, CBU refinery is also handicapped by the lack of access to any other source of crude. It does take in 0.054 MMTPA of imported crude but that represent only 9.32% of the total refinery throughput. These imported crudes are transported via road from Chennai which makes the cost of transportation as high as Rs 284/MT. Due to this high cost of transportation, CBU is mainly dependent on Cauvery basin crude which currently represents 75% of its throughput.

It can be thus concluded that with respect to Cauvery basin crude, ONGC and CBU are in a mutually beneficial relationship, breaking of which will be costly for both. None of them have any other viable option to sell or procure crude.

Basic price

As elaborated in chapter 10, there are four options ONGC faces while negotiating the basic price of the crude. These are reproduced here.

- ♦ **Option A** – Price the crude at FOB of the benchmarked crude at custody transfer point but pay the sales tax on the crude.
- ♦ **Option B** – Price the crude at FOB of the benchmarked crude at custody transfer point.
- ♦ **Option C** – Price the crude at the Import Parity Price (IPP) of the benchmarked crude at the custody transfer point.
- ♦ **Option D** – Price the crude at the IPP of the benchmarked crude at the custody transfer point but pay the sales tax on crude.

The detailed calculations are at Annexure 11.1.

The calculations for import parity prices have been done for Chennai port and excludes any transportation charges from Chennai to CBU due to two reasons.

First, these charges represent the cost of internal transfer of crude since CBU is a part of Chennai refinery.

Secondly, these charges have been factored into the analysis at a later stage while discussing the premiums and discounts and including them in the price options will amount to double counting.

Premium factors for ONGC

Security of supplies

As elaborated earlier, the risk of disruption in the supply of imported crude is much higher than that for domestic crude. Thus, if a refinery chooses to increase its dependence on imports by replacing indigenous crude with imported crude, it is taking an extra risk of running at lower capacity utilisation. If CBU decides to import 434 TMT of crude to replace Cauvery basin crude, in the event of a supply disruption, it can face an increase in the fixed cost to the extent of Rs 0.919/MT (\$0.002/bbl) following the methodology enumerated in Chapter 10. Thus, ONGC can command a premium to this extent. The detailed calculations are at Annexure 11.2.

Augmentation of infrastructure for imports

The CBU refinery takes 54 TMT of imported crudes via road from the Manali (Chennai) refinery. The port occupancy at the Chennai port (Table 10.5) is around 60% which does not suggest that it will be needing any augmentation to import an additional quantity of 434 TMT.

However, one major constraint is the high cost of transporting the crude from Chennai to Narimanam via road. The cost of transportation along the road is 0.85 Rs/MT/Km^a. Thus, if the CBU decides to replace the Cauvery basin crude with imported crude, it will have to take this extra quantity through road. The current estimated costs of transporting 54 TMT is Rs 15 million which will rise to Rs 138 million if it takes 434 TMT of imported crude. Thus, CBU has to incur Rs 283/MT as the cost of transporting the crude from Chennai to Panangudi.

Costs of international procurement

As mentioned earlier, there are certain adjutant costs of imports like LC charges etc. which a importing entity would have to incur. Thus, a shift to domestic crude will save these costs for the refineries. These factors have been analysed on the similar lines as previous chapters.

Letter of credit charges

As mentioned in the earlier chapters, refineries taking the imported crude for the first time may have to pay higher LC charges on the basis of their untested financial position.

^a Data from OCC

The Oil Coordination Committee uses a norm of 0.3% as the LC charges on imports. If CBU is required to pay even 0.1% higher LC charges, its cost of imports will rise by Rs 6.69/MT (\$ 0.019/bbl). Thus, ONGC can ask for a premium to this extent on this account.

Foreign Exchange risks

There might be difference between the rate at which the deal for imported crude is decided and the rate at which the sale actually takes place. This difference may arise either due to change in the price of the crude or just due to fluctuations in the exchange rate since all imports are on dollar basis. Thus, a refinery is exposed to exchange rate risk on the imported crude. For CBU refinery, a 1% depreciation in rupee will cause a rise of Rs 74.44/MT (\$0.220/bbl) for the month of January 2002 on import of Arab Light. Thus, ONGC is in a position to charge a premium to this extent.

Freight diseconomies

The entire quantity of 54 TMT of imported crude processed by CBU is transported via road from the Chennai refinery. Chennai refinery processes about 4.6 MMT of crude every year. Bringing an additional quantity of 0.434 MMT of crude for CBU should not pose any problem for CPCL since the Chennai port can handle a maximum ship size of 140,000 TMT. Thus, ONGC cannot ask for a premium from CBU on this account.

Summary Table

Table 11.2 Summary table for premiums

	Rs/MT	\$/bbl
Premium factors for ONGC		
Augmentation of facilities for imports	283	0.839
Cost of international procurement		
Letter of credit charges	6.69	0.020
Exchange rate risks	74.44	0.221
Total	365.049	1.083
Net premium	365.049	1.083

Strategic option

The above discussion points to the fact that ONGC may not get the import parity price for its crude due to prohibitive costs of moving crude to alternate refineries. It may have to negotiate for FOB price only.

Applying this discount to all the four options for setting the base price, the following surpluses emerge. The detailed calculations are at Annexure 11.1 and Annexure 11.3.

Table 11.3 Surplus for ONGC (\$/bbl)

Refinery	Option A	Option B
CBU	1.48	1.97

This table shows that if ONGC were to get the FOB price for its crude, then even if it gets the full premium as estimated above, it will find it difficult to generate enough surplus from this region.

Under Option B, the surplus left is \$ 1.97/bbl which is \$ 0.33/bbl less than the surplus of \$ 2.3/bbl required by ONGC to fund its exploration activities. Thus, ONGC should try to negotiate at least that price at which \$ 0.33/bbl higher than the price under Option D. This is not a big amount considering that the pricing on FOB would save the refinery the freight from Middle East to East Coast India.

Strategy for marketing North-Eastern crudes

This chapter outlines the considerations that are important in determining the price of the North Eastern crudes.

There are two main collection centres in the northeastern region: Jorhat and Moran. These two supply crude oil to four refineries: Barauni, Guwahati, Bongaigaon and Numaligarh refinery. Of these, Bongaigaon consumed the highest quantity in the year 2000-01 followed by Guwahati and Barauni. Numaligarh consumes a very small quantity of ONGC crudes.

Oil India Limited (OIL) is the other crude producer in this region and supplies crude oil to all refineries in this region, except Haldia refinery, which takes only the imported crudes.

The consumption of indigenous crude by various refineries for the year 2000-01 is shown below.

Table 12.1 Crude oil consumption pattern for refineries (TMT)

Refineries	Total throughput	ONGC crude	OIL crude	Imported
Barauni	3122	300	402	2420
Haldia	3875	-	-	3875
Guwahati	707	310	397	-
Digboi	679	-	679	-
Bongaigaon	1490	552	856	82
Numaligarh	1451	20	1431	
Total	11324	1182	3765	6377

Source: OCC

As shown above, Haldia refinery is processing only the imported crude.

Moreover, since there is no infrastructure to move the crude from North East to Haldia, Haldia is not a potential customer for North Eastern crudes.

Digboi refinery, however, is a potential customer though it is not processing the ONGC crudes currently since there is a pipeline carrying the crude from Moran CTF to Digboi refinery.

Table 12.1 also shows that out of total indigenous crude sales of 4.947 MMT, ONGC accounts for only 23% whereas OIL accounts for the remaining 76%. And in so far as all the crude supply pipelines are also owned by OIL, ONGC does not seem to have much bargaining power in the Northeast.

Moreover, as the table below shows, the projected production from the Assam region is expected to decline in the tenth plan period.

Table 12.2 Projected production from North East region (MMT)

	2002/3	2003/4	2004/5	2005/6	2006/7
Production	2.013	2.057	2.066	2.054	2.004

There are two factors that determine the options available to ONGC.

- 1) **Infrastructure** – There is no physical infrastructure at the disposal of ONGC to move the crude to the port for exports or for coastal movement within India. Even within the NorthEast, all the supply pipelines are owned by OIL.
- 2) **Production** – The production of ONGC fields is very small compared to OIL and moreover it is declining.

This shows that ONGC has got no option but to sell its crudes to refineries in the region.

On the other hand, OIL being a major producer in the region, refineries have an alternate option for crude procurement. With a volume of only 1 MMTPA, there isn't much bargaining power with ONGC.

Basic price

As elaborated in chapter 10, there are four options ONGC faces while negotiating the basic price of the crude. These are reproduced here.

- ♦ **Option A** – Price the crude at FOB of the benchmarked crude at custody transfer point but pay the sales tax on the crude.
- ♦ **Option B** – Price the crude at FOB of the benchmarked crude at custody transfer point.
- ♦ **Option C** – Price the crude at the Import Parity Price (IPP) of the benchmarked crude at the custody transfer point.
- ♦ **Option D** – Price the crude at the IPP of the benchmarked crude at the custody transfer point but pay the sales tax on crude.

The detailed calculations are at Annexure 12.1.

The calculations for import parity prices have been done taking Haldia port as the discharge port and excludes the transportation costs of moving the crude from Haldia to respective refineries because it will be negotiated as to who will bear these costs.

Following the format in the previous chapters, discussed below are the potential factors that could earn ONGC some premium.

Premium factors for ONGC

Alternative options for refineries and ONGC

The main factor that has to be considered in pricing the Assam crudes is the options that the refineries and the ONGC have. Three refineries in the region- Haldia, Barauni and Bongaigaon are already taking imported crudes while Digboi, Numaligarh and Guwahati are dependent only on the indigenous crudes. The imported crude to Barauni refinery is transported via the Haldia-Barauni pipeline which is owned by IOC and has the capacity of 4.2 MMTPA. Given the installed capacity of Barauni refinery as 4.2 MMTPA and the average throughput of 3.1 MMTPA, the pipeline capacity is not a constraint.

The average occupancy at the Haldia port during the year 2000-01 was 63-69% (table 10.5). Given the total crude oil import volume at the port of 6.2 MMTPA, importing an additional 0.3 MMTPA (to replace the ONGC crude) should not pose any problem for the Barauni refinery.

Bongaigaon refinery processed around 0.082 MMT of imported crude in the year 2000-01. The imported crude to Bongaigaon refinery is transported via the Barauni-Bongaigaon pipeline with the capacity of 3 MMTPA. Thus, this pipeline is not a bottleneck for BRPL. The nearest port for BRPL is Haldia and as mentioned above, the port occupancy does not rule out additional imports of 0.082 MMTPA.

Thus, infrastructural bottlenecks are not a hindrance in these refineries taking in extra imported crude to replace the ONGC crude.

Digboi and Numaligarh are heavily dependent on the OIL's crude and hence the chances of their importing the crude to replace the ONGC crude are very less.

Guwahati refinery is dependent on ONGC for 43.84% of its crude throughput. But it also accounts for 51.6% of total ONGC crude sales along with Barauni refinery (which is also owned by the same company, IOC). Thus, the possibility of ONGC terminating the supply contract with IOC for this region are very less. Thus, Guwahati is also not on a weak footing with respect to ONGC for sourcing its crude.

Security of Supplies

This is an issue with those refineries which are taking the imported crudes and also with those which are processing only the domestic crudes. For the former, dependence on imported crude will expose them to risk of disruption in supplies whereas for the latter, it represents the avoided cost of risk of supply due to their

intake of domestic crude, in the absence of which they will be forced to either operate at lower capacity or depend on imported crudes.

However, there are two factors that may have an opposite effect. Firstly, OIL is the major producer in the region and can supply to all the refineries. Secondly, out of total throughput of 11 MMTPA for the region, ONGC's 1 MMTPA is cannot be perceived to have any substantial effect on the security of supplies in the region. As such the region is accounting for only 8.5% of the total imported crudes in the country. So a disruption of 62.21 MMT would not have a huge impact on the region.

Cost of international procurement

As mentioned earlier, the less established refineries may have to pay a higher LC charge while importing crude. Just 0.1% increase in LC charges will raise the cost of imports for the refineries by Rs 7.43/MT (\$0.022/bbl). Thus, ONGC can charge a premium to this extent.

However, Digboi and NRL cannot be expected to pay this premium because it is processing only the OIL's crude. Also, Barauni and Guwahati refineries, being a part of IOC which is a Fortune 500 company, may not pay a higher LC charge on imports. And since Bongaigaon is importing only 0.082 MMTPA of crude, this factor is not very important for it also. Thus this factor is not important for negotiations in this region.

Freight diseconomies

In the regulated scenario, IOC was the sole canalising agency for the refineries taking imported crude. Due to this large volume, it was able to economise on the freight. However, if the refineries decide to import individually, the requirement may not be as much as to fill a VLCC tanker and hence they will bring crude in smaller vessels which would mean higher freight.

However, an analysis of the imported crude requirement of the refineries shows that this factor is not very important.

The Barauni refinery is already taking 2.4 MMTPA of imported crude and taking an additional quantity of 0.3 MMTPA would not raise the import cost on any account.

The imported crude requirement of the Bongaigaon refinery is only 0.082 MMTPA which can be clubbed with Barauni refinery.

Digboi and Numaligarh refineries do not process any imported crude or ONGC crude and hence will be not be affected.

The Guwahati refinery takes 0.310 MMTPA of ONGC crude and if it decides to replace it by imported crudes, it can be easily clubbed with Barauni and Haldia (both owned by IOC) and hence would not necessitate any additional costs of imports for the refinery.

Thus, there will no premium on this account for any refinery.

However, there is one factor that may force ONGC to give a discount on its crude. This is discussed below.

Discount factor for ONGC

High BS&W of the Assam crudes

The average BS&W in the Assam crudes is 0.2% which is higher than the international standard of 0.02%. ONGC would either have to bring the crude to the international standard before dispatching it to the refineries or it would have to accept a discount to the extent of the cost which has to be incurred in doing so. As provided by ONGC, it costs about Rs 100 million to desalt 1 MMT of crude. Thus the annutised cost of desalting 2 MMT of crude can be estimated as Rs 15.53/MT (0.046 \$/bbl). The detailed calculation is at Annexure 12.2.

Summary table

The above analysis shows that there is no strong reason for refineries to yield a premium to ONGC for its crude. However, high BS&W in the crude will probably force ONGC to give a discount.

Table 12.3 Summary table

	Unit	Barauni	Guwahati	Digboi	BRPL	NRL
Discount factors for ONGC						
BS&W problem	Rs/MT	15.53	15.53	15.53	15.53	15.53
Total Discount	Rs/MT	15.53	15.53	15.53	15.53	15.53
Average Net Discount	Rs/MT	15.53	15.53	15.53	15.53	15.53
Average Net Discount	\$/bbl	0.046	0.046	0.046	0.046	0.046

Thus, for the NorthEastern refineries, ONGC may have to yield a discount of Rs 15.43/MT or 0.046 \$/bbl.

Strategy for North Eastern crudes

Given the fact that ONGC does not have any alternate option to sell its crude and given the fact that ONGC's crudes are not of international quality, it will be difficult for it to demand import parity price for its crude. The refineries are in a

better position to source the crude either from OIL or take the imported crude and hence will not give import parity price to ONGC. Thus, out of the four pricing options mentioned earlier, only two are possible – those based on FOB.

The surplus left for ONGC under the two pricing options are shown below. The detailed calculations are at Annexure 12.2.

Table 12.4 Surplus for ONGC (\$/bbl)

Refinery	Option A	Option B
Barauni	1.26	1.77
BRPL	1.26	1.77
Guwahati	1.26	1.77
NRL	1.26	1.77
Digboi	1.26	1.77

This table shows that surplus generated in North East may not be enough if the pricing is done on FOB basis.

However, if ONGC can negotiate for an additional \$ 0.53/bbl under Option B, it can make the required surplus of \$ 2.3/bbl. This amount of \$ 0.53/bbl is not high considering the fact that pricing crude on FOB effectively saves the freight from Nigeria to East Coast India.

PART-2

Overview of the Indian gas industry

Although the use of natural gas has increased rapidly, it accounts for only around 11% of the primary energy use in India. Till the late 1980s the demand lagged behind the production potential mainly because of lack of infrastructure. However, in the 90's, the demand has exceeded the supply. Gas reserves and production trends in India are presented in Annexure 13.1.

In view of the shortage of gas production and supply compared to demand, the government of India allocates gas to all consumers. The current gas allocation is 105.90 MMCMD whereas the domestic gas production in 1999-00 had been only about 78 MMCMD^a.

The power and fertiliser sectors have been allocated most of the gas as shown in the Table below.

Table 13.1 Sector-wise gas allocations (MMCMD)

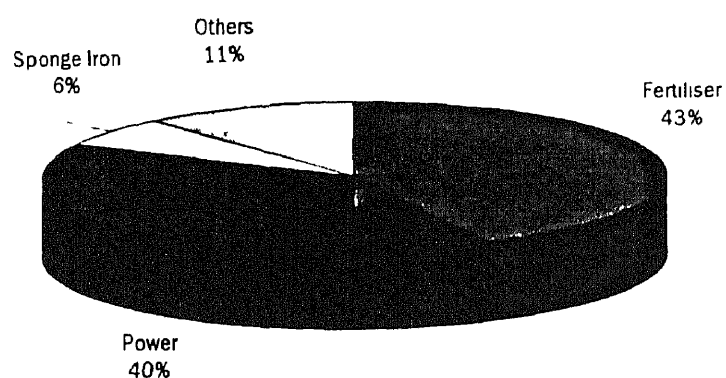
Sector	Allocation (MMCMD)
Power	42.76
Fertiliser	26.35
Others	36.79
Total	105.90

Source: GAIL

The power and fertiliser sectors together consume about 80% of the gas today. The sponge iron units consume another 10%. The balance goes to industrial units where it replaces mostly fuel oil and some LPG. Gas is also supplied to the residential and the commercial sectors in Mumbai, Delhi and a few towns of Gujarat, Assam and Tripura. This gas is used for cooking only, as space heating is not required. The daily requirement of households is only around 1 cum. With such low requirements and the subsidy on domestic LPG, the demand from this sector will continue to be low. The use of CNG in lieu of petrol has been popular in Mumbai and Delhi. Gas use by various industries has been discussed further in Annexure 13.1.

^a Source: Basic Statistics on Indian Petroleum and Natural Gas, 1999-2000, MoPNG

Figure 13.1 Sectoral gas sales (1998/99)



Source. GAIL

Area wise and sector wise use of natural gas in 1998/99 is shown in Table below:

Table 13.2 Gas utilisation: 1998/99 (MMCMD)

Area	Fertiliser	Power	Sponge Iron	Others	Total
Western Offshore					
Uran	5.0	4.7	1.4	0.7	11.8
HBJ	13.0	9.1	-	2.5	24.6
Hazira	2.7	-	2.0	1.2	5.9
Western Onshore	1.2	4.2	-	1.4	6.8
Rajasthan	-	0.4	-	-	0.4
K. G. Basin	1.7	2.2	-	0.1	4.0
Assam	0.0	0.4	-	0.1	0.6
Tnpura	-	0.8	-	0.0	0.8
Cauvery Basin	-	0.0	-	0.1	0.1
Total	23.6	21.9	3.5	6.1	55.1

Source. GAIL

According to Hydrocarbon Vision 2025, the power and fertiliser sectors would dominate gas consumption and the demand would build up as shown below.

Table 13.3 Total gas demand (MMCMD)

	1998/99	2001/02	2006/07	2011/12	2024/25
Power					
Scenano 1*	22	40	67	90	153
Scenano 2**	22	67	119	168	208
Fertilizer	24	54	66	83	105
Others#					
Scenano 1	9	23	33	43	64
Scenano 2	9	30	46	63	78
Total					
Scenano 1	55	117	166	216	322
Scenano 2	55	151	231	313	391

* gas at \$4/MMBtu

** gas at \$3/MMBtu

other sectors account for 20% of total demand in 2002 and thereafter

Our own estimates of gas demand are more conservative, as shown in the next section.

ONGC draws up long term profiles of gas production every year. The gas production projections by ONGC is shown in table below.

Table 13.4 Projected gas production by ONGC (MMCMD)

	2002-03	2003-04	2004-05	2005-06	2006-07
Gas (MMCMD) ^a	50.48	48.88	46.05	46.51	47.04

Source. ONGC

Current projections show that the total gas production would decline steadily until the Bombay High gas cap is brought into production. This is expected between the years 2015 and 2020. The declining production profile coupled with the projection of rising demand shows a widening demand-supply gap. This implies that exploration efforts need to be stepped up and the feasibility of importing gas from the neighbouring countries examined seriously. The initiatives and prospects for exploration and option for importing gas through pipelines have been described in Annexure 13.1. Various LNG import projects have simultaneously been planned in India. The status of these projects has been discussed in later sections of this chapter.

^a Does not include production from joint venture fields

Gas supply sector organisation

The gas supply sector in India is dominated by public sector enterprises under the administrative control of the Ministry of Petroleum. Ninety percent of the gas is produced by two state owned oil companies, the Oil and Natural Gas Corporation (ONGC) and Oil India Limited (OIL). The balance comes mostly from the medium sized fields - Panna, Mukta and Tapti in the western offshore and Ravva off the Andhra coast - operated by joint ventures of ONGC. Several small gas fields operated in the private sector are also producing gas but their production does not add up to much.

The gas produced by ONGC is marketed by GAIL except gas from isolated marginal fields marketed direct by ONGC. OIL, which operates mainly in Assam and also in Rajasthan sells gas mainly through its own arrangements and partly through GAIL. The gas from Panna-Mukta-Tapti and Ravva is bought by GAIL on behalf of the government. All of this gas is sold only to consumers who are allocated gas by the Government of India. The private operators of small gas fields are free to select their customers. The gas price to be charged by ONGC and OIL and the transportation charges along the HBJ pipeline of GAIL are fixed by the government. Gas from private fields is sold at negotiated prices.

The gas industry infrastructure

The Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline network is the major gas transmission line in India, owned and operated by the Gas Authority of India Limited (GAIL). It starts at Hazira in Gujarat and passes over Rajasthan, Madhya Pradesh, Uttar Pradesh into Haryana. It is 2300 km long with a capacity of 33.4 MMCMD. Spur lines at various points in Gujarat, Rajasthan, Uttar Pradesh, Delhi and Haryana feed power plants, fertiliser plants and industries.

Wet gas from the offshore South Bassein field, off the coast of Maharashtra, is fed by 216 km sub-sea lines of 36" and 42" diameter to ONGC's sweetening and fractional separation plant at Hazira. The gas handling capacity at the Hazira terminal is 41 MMCMD.

With several LNG terminals being planned on the west coast of India, GAIL plans an investment of Rs. 30 billion to expand the HBJ capacity to 60 MMCMD by 2003. GAIL also plans to extend the HBJ pipeline to Ludhiana in Punjab.

In addition to the HBJ pipeline, there are regional gas grids of varying sizes in the states of Gujarat, Andhra Pradesh, Assam, Maharashtra, Rajasthan, Tamil Nadu and Tripura. Most of these regional pipelines (about 725 km) were constructed and operated by ONGC but ownership and operation of these gas grids were passed on to GAIL in the nineties. The present grid capacity is based on the gas availability from the producing areas as well as the outlook for future gas production. In view of the increased availability of gas in the KG basin, GAIL has announced plans for augmenting pipeline capacity in Andhra Pradesh.

Distribution

The Mahanagar Gas Limited, a joint venture between GAIL and British Gas is supplying gas to around 50,000 houses in Mumbai as well as small industrial and commercial units and CNG filling stations. The Indraprastha Gas Limited, a joint venture of GAIL and BPCL is supplying gas in Delhi to around 1000 houses and 80 CNG stations. At the instance of the Supreme Court, the fleet of buses, taxis and rickshaws in Delhi is being converted to CNG. The other cities with natural gas distribution systems are Vadodara, Surat and Ankleshwar in Gujarat and a few towns in Assam and Tripura in the north-east.

The objective of the marketing strategy of gas produced by ONGC is to maximise the netback to ONGC from selling gas. This can generally be achieved by selling gas to the market segment consisting of the high imputed value sectors like power generation, fertilisers, captive power, etc. at prices approaching their opportunity costs. Imputed value of gas at any location is the maximum payable for gas if it has to replace the cheapest alternative fuel at that particular location. This is the way gas is sold in mature markets all over the world. It is interesting to note that ONGC priced gas on this basis in Maharashtra in 1978 and extended it to Gujarat in 1982. This principle of pricing was challenged by some consumers in the Supreme Court but the court upheld the prices. Since 1987, however, gas has been sold at uniform prices to all customers at the same location. The price is now linked to international prices of fuel oil. The pricing policy of domestic gas and issues in sales contracts between GAIL and consumers have been discussed in Annexure 13.1.

The steps that have been followed to formulate the marketing strategy for ONGC gas are as follows:

- the state-wise gas demand has been estimated till 2006/7 for power, fertiliser and industrial units
- imputed values for each industry type has been evaluated at select locations
- gas demand that can be captured at each imputed value has been assessed
- the various pricing options for ONGC gas has been discussed and strategy to be adopted to obtain the best deal in each case has been framed.

Estimation of gas demand

Gas demand has been estimated till 2006/7. As power generation and urea production consume 80% of the gas available, these sectors have been examined closely for projecting the gas demand. Gas demand from glass, paper and cement industries have also been projected. Captive generation is a promising area for gas use and this area has also been examined. Gas use in city distribution is likely to be limited and can be estimated only through detailed surveys. We have accordingly not looked at this sector.

TERI estimates of sector-wise gas demand is shown in Table below.

Table 13.5 Total gas demand (MMCMD)

	Existing	2006/7
Power	49.37	71.79
Fertiliser	40.22	40.22
Cement	4.84	6.87
Paper and pulp	3.35	5.04
Glass	1.87	2.65
Total Industries *	10.06	14.56
Captive	5.78	10.36
Total	105.43	136.93

- Does not include industries other than cement, paper and glass.

The detailed methodology for gas demand estimations, state-wise and sector-wise is shown in Annexure 13.2.

The demand numbers above do not refer to any price level. To find the demand at different prices, we develop the imputed values at different locations.

Imputed values

Imputed value of gas is the price of gas at which the cost of generation or production in a gas based plant equals the cost of generation/production using an alternative fuel, at a particular location. Thus imputed value indicates the maximum price for gas at which it is competitive with the cheapest alternative fuel. The methodology used has been illustrated in Table below.

Table 13.6 Methodology for calculating imputed value of gas

Cost of generation/production	Gas based	Competing technology
Capital cost	a	c
Operation and maintenance cost	b	d
Fuel cost	X (unknown)	e
Total cost		$f = c + d + e$
Imputed value of gas		$X = f - a - b$

Power generation

The imputed values for power generation have been computed against domestic coal. The detailed methodology is provided in Annexure 13.3. The locations selected are places where power projects are proposed to be set up.

Table 13.7 Imputed values of gas in power generation (\$/MMBtu)

Location	Domestic coal*
Bawana	4.70
Fandabad	4.62
Hisar	4.99
Doraha	5.03
Bhatinda	5.20
Govindwal	5.09
Dholpur	4.32
Suratgarh	5.35
Anta	4.36
Kawas	5.03
Ghandhar	4.93
Mundra	5.03
Pipavav	5.26
Auraiya	4.40
Unchahar	4.07
Jawaharpur	4.44

Location	Domestic coal*
Anpara	3.79
Partapur	5.17
Bhandar	4.23
Rosa	4.79
Sipat	2.92
Korba	2.97
Vindhyachal	3.98
Raigarh	2.97
Trombay	4.75
Chandrapur	4.03
Vizag	3.66
Raichur	5.46
Chennai	4.41
Kayamkulam	5.57
Guwahati	4.78

* at locations within 1500 km of domestic coal fields, coal without washing has been considered otherwise washed coal has been considered as the suitable alternative fuel

Urea production

Imputed values of gas in urea production have been estimated against imported urea at a long term average cif price of \$150/MT. The landed cost of imported urea at the Indian port with a cif price of \$ 150/MT, an exchange rate of Rs 46 per US dollar and 25% import duty^a, the landed cost at the Indian port would be Rs 8625/MT.

Table 13.8 Imputed values of gas against urea imports at cif \$150/MT

Location	Imputed values (\$/MMBtu)	
	New plants	Expansion units
Babrala	4.51	4.99
Jagdishpur	4.65	5.13
Shahjahanpur	4.71	5.19
Gorakhpur	4.70	5.18
Hazira	3.78	4.27
Nangal	4.49	4.97
Thal	3.86	4.35
Kota	4.27	4.76
Panki	4.58	5.07
Phulpur	4.65	5.13
Barauni	4.09	4.58
Durgapur	3.86	4.35
Nellore	4.04	4.52
Goa	3.78	4.27
Kochi	3.78	4.27
Kakinada	3.78	4.27
Vizag	3.78	4.27
Chennai	3.78	4.27
Mangalore	3.78	4.27
Tuticonn	3.78	4.27

^a Currently there is no import duty on imported urea

The imputed value against the urea price of Rs 7500/MT recommended by the Expenditure Reforms Commission (ERC) has also been computed.

The ERC has recommended that Rs 1,900/MT be allowed as concession to new units based on LNG while the farmgate price paid by the consumer is pegged at Rs 7000/ MT. In that case, the producer would receive a net price of Rs. 8,600/MT after deducting Rs 300/ MT as the marketing cost. The imputed value of gas against this producer price is \$ 4.24/MMBtu for an expansion of a gas based plant and \$4.85/MMBtu for conversion of naphtha based plant to a gas based plant.

Details of imputed values of gas in urea production is discussed in Annexure 13.3.

LNG vs Naphtha in urea production

Any urea producer wishing to change over to LNG would have to enter into a long-term contact (15-20 years) with LNG suppliers. In a situation of naphtha surplus in the country, the question remains if future naphtha prices could drop to such low levels as to become competitive with the LNG option. If such were the case, urea producers should stay with naphtha rather than opting for LNG. To examine such possibility, we have calculated naphtha export parity prices at three locations: Kota, Panki and Phulpur shown in Table 13.9. For comparison, naphtha import parity prices have also been presented. Detailed calculation of export parity and import parity prices are given in Annexure 13.3.

Tables 13.9 Naphtha export parity and import parity price

Locations	Naphtha export parity price (\$/MT)	Naphtha import parity price (\$/MT)
Kota	200	281
Panki	198	293
Phulpur	208	286

The imputed values of gas against the above naphtha prices at Kota, Panki and Phulpur are presented in the Table below with details in Annexure 13.3.

Table 13.10 Imputed values of gas against naphtha

Locations	Imputed value against naphtha export parity price (\$/MMBtu)	Imputed value against naphtha import parity price (\$/MMBtu)
Kota	4.70	6.54
Panki	4.66	6.79
Phulpur	4.87	6.64

Industries and captive generation

Imputed values for cement and paper industry have been calculated at the identified clusters against domestic coal. For the glass industry, imputed values have been calculated against LPG ex-Koyali, Mathura, Mumbai and Vizag. For captive generation, imputed values have been calculated against naphtha ex-Koyali, Mathura, Mumbai and Vizag. . The methodology is provided in Annexure 13.3.

Imputed values of gas for industries and captive generation have been computed on calorie equivalence. The Table below presents the imputed values.

Table 13.11 Imputed values for industries and captive generation

Location	Imputed values (\$/MMBtu)
Cement and paper industry against domestic coal	
Sikka	2.35
Kota	1.79
Delhi	1.99
Pipavav	2.36
Surat	2.16
Satna	1.36
Amntsar	2.24
Chandrapur	1.64
Malkhed	2.01
Tadipatri	2.19
Glass industry and city distribution against LPG	
Ex-Koyali	10.10
Ex-Mathura	10.56
Ex-Mumbai	9.93
Ex-Vizag	9.80
Captive generation against naphtha	
Ex-Koyali	7.29
Ex-Mathura	7.89
Ex-Mumbai	7.10
Ex-Vizag	7.12

Industry in Gujarat is now paying a gas price of Rs 2850/thousand cubic metres which equals \$1.56/MMBtu. In addition they pay royalty of 10% (\$0.16/MMBtu) and transport charges depending on location. The domestic gas price is due for a revision and may soon exceed \$3/MMBtu. The consumers will not surrender their allocations and change to coal. Indications are that most of them would continue to use gas. The imputed values of \$1.83 - 2.39/MMBtu calculated for industrial units, therefore, underestimates the price they would be willing to pay. It is possible for cement units to reduce energy consumption from 930 kcals/kg, assumed by us in computing the imputed value, to 700 kcals/kg. There are additional benefits in terms of savings in power consumption, refractory

consumption and clinker quality in changing over to gas. Cement producers should be able to pay between \$2.9–3.6 / MMBtu depending on location.

Having projected the gas demand and estimated the maximum price payable for gas at each location, the next section evaluates the gas demand that can be captured at each imputed value.

Profile of gas demand

Time profile of gas demand

Putting together the several components of potential gas demand we get the following time profile.

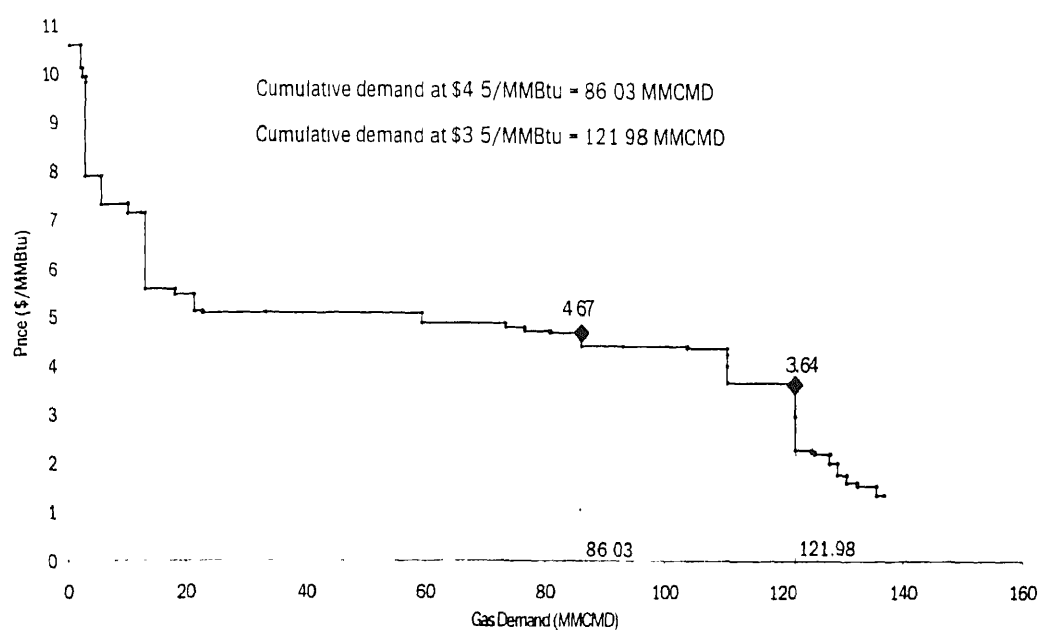
Table 13.12 Demand of gas at various prices (MMCMD)

	Existing	2006/7
Demand at gas price \$3.50/MMBtu		
Power	46.33	68.75
Fertiliser	40.22	40.22
Industries	1.87	2.65
Captive	5.78	10.36
Total demand	94.20	121.98
Demand at gas price \$4.50/MMBtu		
Power	21.04	32.80
Fertiliser	40.22	40.22
Industries	1.87	2.65
Captive	5.78	10.36
Total demand	68.91	86.03

Price profile of gas demand

Imputed values of gas have been used along with the sectoral gas demand estimates to arrive at the price profiles of gas demand in 2006. All India price profile for 2006 is shown in Figure 13.2. Details of India and regional price profiles are shown in Annexure 13.4.

Figure 13.2 All India price profile of gas demand in 2006



LNG import projects

In view of the problems faced in importing gas by pipelines, the LNG option has been pursued to meet immediate needs for imported gas. Proposals for constructing LNG terminals have been made by various consortia of Indian and multinational oil and gas companies and promoters of power plants. The LNG trade is undergoing a transformation as new suppliers emerge in West Asia. The downturn of LNG demand in South Korea and Japan has made India a key market for LNG.

The supply sources identified by promoters of LNG import proposals in India are listed in the Table below.

Table 13.13 Identified sources of supply to proposed LNG terminals in India

LNG terminal	Capacity (MMTPA)	Supply source	Remarks
Jamnagar	5.0	Iran	
Pipavav	3.0	Under identification	MoU signed earlier with Yemen voided
Dahej	5.0	Qatar	
Hazira	5.0	Shell group's sources	
Trombay	3.0	Total Elf Fina sources	
Dabhol	5.0	Oman (1.7 MMTPA) Abu Dhabi (0.54 MMTPA)	Balance quantity yet to be sourced
Kochi	2.5	Qatar	
Ennore	2.5	Qatar	
Kakinada	2.5	To be decided	Malaysia, a contender
Gopalpur	5.0	Australia	
Total	38.5		

The status of proposed LNG projects in India has been discussed in Annexure 13.5. The projects that are likely to go through by 2006 are listed in the Table below.

Table 13.14 Expected LNG imports

Year	Quantity		Cumulative		Location (MMTPA)
	MMTPA	MMTPA	MMTPA	MMCMD	
2004	4.5	4.5	18		Dahej (2.5), Dabhol (2)
2005	2.5	7	28		Dahej expansion
2006	2.5	9.5	38		Hazira (2.5)

Gas marketing strategy

As stated earlier, the objective of the marketing strategy is to maximise the netback to ONGC from selling gas. Gas demand from market segments having higher imputed values have to be targeted.

Though domestic gas price is now linked to international prices of fuel oil. The linkage is under review and full parity with fuel oil is expected in the near future. The gas price should get another boost in 2004 when LNG arrives at Gujarat. Thus, the gas price may pass through some intermediate stages before fully market driven prices are re-introduced.

A better fuel oil linkage

The current consumer price of gas at landfall points is linked to the price of a basket of fuel oils as shown in the table below:

Table 13.15 Natural Gas Pricing against a basket of Fuel Oils

Year	Percentage of LSHS/FO price	
	General Price	Concessional Price for the NE States
1997-98	55%	35%
1998-99	65%	40%
1999-2000	75%	45%

The price is determined and notified by GAIL with the approval for the Ministry for every quarter depending upon the average price of the following basket of fuel oils (with equal weights to each type) based on the figures obtained from Platt's Oilgram for the previous quarter.

- Cargoes FOB, Med Basis, Italy (1% Sulphur)
- Cargoes CIF NEW Basis, ARA (1% Sulphur)
- Singapore, FOB, HSFO 180 cst (3.9% Sulphur)
- Arabian Gulf, FOB, HSFO 180 cst (3.9% Sulphur)

The price varies between the floor of Rs 2150/MCM (thousand cu mtrs) and the ceiling of Rs 2850/MCM. The revision to full parity with fuel oil would not be effective unless the ceiling price is revised upward. At crude oil prices of \$22-28/bbl, the gas price is expected to be \$3.45-4.40/MMBtu or Rs 6296-8013/MCM (assuming 10,000kcal/cu.mtr.). In view of the estimated Long Range Marginal Cost of production of Rs 1800/MCM for ONGC (Sankar Committee, 1997), it is unlikely that ONGC would be allowed by the government to charge such high prices. The government has allowed fuel oil linked prices in two other cases, Panna-Mukta-Tapti and Ravva. In the first case there is a ceiling price of \$3.11/MMBtu and in the second case the ceiling price is \$3/MMBtu. Accordingly, a ceiling for ONGC may be imposed somewhere between \$2.5-3.0/MMBtu.

ONGC should try to negotiate a high ceiling price but it may be difficult to do so. In view of the recent experience with high oil prices, consumers would be sensitive to the ceiling. Besides, a high ceiling may give rise to the demand for a low floor price. It would be more feasible for ONGC to negotiate a better fuel oil basket. So long as the ceiling price is acceptable, the consumers may be less sensitive to a higher price within the ceiling. This could be done by choosing only low sulphur fuel oils, altering the weight in favour of low sulphur fuel oils in the basket and by changing fob prices to cif.

Pooled price for LNG

What would be the effect of LNG on the prices of domestic gas? Would domestic gas continue to be sold at fuel oil linked prices while LNG is imported and sold at higher prices? It is difficult to answer the question now as little is known on how imported LNG is going to be priced. So far as is known, the cif LNG prices at the Gujarat coast would be:

At \$18/bbl JCC: \$2.55-2.75/MMBtu

At \$25/bbl JCC: \$3.45-3.80/MMBtu

Adding 40 cents/MMBtu for regasification, the gas price ex-receiving terminal would come to \$2.95-4.20/MMBtu. We may add 10 cents/MMBtu for locations in the southern and eastern coast for additional ocean freight.

If the gas is put into the HBJ pipeline, it would reach consumers in western and northern India with the addition of another \$1/MMBtu as the transportation cost. The price to HBJ consumers would rise from \$3.95-\$5.20/MMBtu as the crude oil price goes from \$18/bbl to \$25/bbl.

It should be noted that Petronet LNG has not yet tied up any customer. Apparently the problem is that the LNG price is open ended, without a cap.

According to press reports, one suggestion to solve the problem is to pool the prices of domestic gas and LNG imported by Petronet. The domestic gas price is already a pooled price with customers paying the same price for ONGC gas and costlier gas from private fields. The proportion of costly gas would increase if LNG is also pooled in. One way of pooling would be to mix 20 MMCMD of LNG with 60 MMCMD of gas now available (not counting the north-east). The imputed values computed for important customers along HBJ are reproduced below: (\$/MMBtu)

Fertiliser expansion - 4.24

Fertiliser conversion -4.85

Fertiliser existing - 5.05

NTPC Anta - 4.36

NTPC Auraiya -4.40

NTPC Gandhar - 4.93

NTPC Kawas - 5.03

This shows that the expected netback price at Dahej would be at least \$3.25/MMBtu. As we have seen earlier, regasified LNG would cost \$3.45/MMBtu at a JCC price of \$25/bbl. If this has to be sold at \$3.25/MMBtu, the domestic gas price has to be capped at \$3.2/MMBtu. This does not pose a problem. However, if LNG has to be covered at a JCC price of \$30/bbl, the domestic cap would be \$2.9/MMBtu. If the expected netback is lower, the cap will be lower. If the proportion of domestic gas is taken to be lower to cover decreasing production, the cap would be lower still. **The implication for ONGC is that if pooling is unavoidable, ONGC must be fully involved in the price fixing exercise.**

NELP gas

As seen above, pooling would lock the price of the bulk of ONGC gas into fuel oil linkage. However, ONGC would be free to get a better price for gas from NELP blocks. Private gas producers would be similarly placed. When LNG becomes available, the price of this gas could be raised to import parity. However, most of this gas is expected to be found around Gujarat or Andhra Pradesh where gas-to-gas competition may keep the price down. In view of the possibility of increasing the gas price, it would be prudent not to sell this gas on long term contracts. At least, the price should be kept flexible.

Individual vs bulk sales

Price negotiations with consumers would require the building up of special teams and there would be a cost attached to it. ONGC may avoid a part of this cost by selling gas in bulk to GAIL or other such agencies who would undertake the tasks of transport and marketing. This would be a good choice if a number of agencies were available to do this job. In such a case, the agency could be selected through competitive bidding and the netback to ONGC could be maximised. For quite some time, GAIL may be the only marketer but there is a chance that British Gas or the oil marketing company could enter the market and make it competitive. Bulk selling may be more feasible in cases where the marketing risk appears to be large. These decisions could be taken on the merits of the particular case.

The price for bulk sales would be fuel oil linked. As in the case of gas sold through GAIL, the choice of fuel oils would be important, as would be the price ceiling or the linkage. These could vary between regions depending on the customer profile. ONGC would need to have a clear idea of the purchasing power of the customers even while negotiating bulk sales.

Bulk prices will be linked to fuel oil. What basket is chosen will be decided by bargaining. ONGC has to settle depending on their own assessment of what the market will bear. GAIL will earn a return on pipelines and the margin. No commission has to be paid by ONGC.

Transmission of gas is going to be a regulated business. Normally, this would not be attractive compared to the upstream sector and it may be necessary for ONGC to transport gas only in specific cases where a transporter is not available or the available transporter is inefficient, which means the netback to ONGC would suffer. In such cases, regulation may require ONGC to separate the accounts for selling and transportation. ONGC may also have to provide access to the pipeline to other parties.

Coping with variable prices

The work of development or additional development in a gas field would be undertaken only when the incremental cost is compensated by the incremental income. The long term gas production profile of ONGC shows that gas production in some areas will increase up to 2006/7. Any additional investment required for increasing the flow of gas is to be justified by the expected revenues. So far as these fields are concerned, it is expected that all the producible gas has to be sold to GAIL at prices fixed by the government. As we have seen, the price of this gas is likely to reach fuel oil parity. What is the expected fuel oil price over

the economic life of the investment? The answer to this question depends on the assumptions as to the long term behaviour of crude oil prices. The various price forecasts available for 2020 are:

Energy Information Administration : \$22/bbl.

International Energy Agency : \$30/bbl.

European Commission : \$ 28/bbl.

These forecasts should be compared to the OPEC announcement that the price of the OPEC basket will be kept within a band of \$22-28/bbl. As an oil and gas producer, ONGC cannot be guided by these forecasts in evaluating development proposals. Shell takes the benchmark price of \$14/bbl so that all projects of Shell remain profitable even when the oil price drops to that level. ONGC has to work out a suitable benchmark price depending on their perception of risks.

Where ONGC is free to price the gas, the uncertainties linked with a variable gas price could be avoided by selling the gas at a steady price. This would be welcome by Indian gas consumers as many of them are in the public sector and are, therefore, averse to taking risks. Hardly any gas seller would, however, agree to a steady price which eliminates the possibility of large gains. A compromise acceptable to both the buyer and the seller would be a variable price subject to a floor and a ceiling. Generally, the ceiling would be dictated by the cost of alternative fuels to the buyer whereas the floor would be a function of the production cost.

Contract conditions

Gas consumers in India may have difficulties in signing long term contracts with stiff take-or-pay provisions. Gas suppliers who depend on project finance for developing their fields may find such terms unavoidable. ONGC could have an advantage here, over other suppliers. If the market is competitive, ONGC could offer more flexible contract conditions if that leads to a higher market share. In some cases, a similar advantage could be derived by offering Rupee prices instead of Dollar denominated prices.

The pricing and other conditions would have to be innovative if gas is to be sold to industrial consumers. Most of these may be able to afford only intermittent supplies, depending on movements in coal and fuel oil prices. A two-part transportation tariff in which fallback suppliers do not pay capacity charges could help in developing such customers. It would be in the interest of ONGC to influence regulatory policy in this regard.

PART-3

Introduction

LPG sales have recorded an average growth of 10.6% over the last decade. While earlier demand far exceeded supply, of late, with the commissioning of new refineries, supply constraints have been relaxed considerably. In fact, recent trends reflect saturation in domestic LPG sales. Registered waiting lists of oil marketing companies have been liquidated and additional LPG demand would primarily emerge from rural and semi-urban areas. Overall, the demand for LPG is expected to grow at an annual rate of 8% over the Tenth Plan period.

LPG availability from domestic sources, i.e., refineries and fractionators, however, would be well below expected demand, necessitating imports. LPG demand-supply outlook is summarised in Table 14.1. (Detailed description of the Indian LPG market is presented in Annexure 14.1).

Table 14.1 LPG demand-supply outlook (TMT)

Year	Demand	Supply	Deficit
2001/02	8055	6428	1627
2002/03	8776	6328	2448
2003/04	9528	6766	2762
2004/05	10310	6903	3407
2005/06	11123	7766	3357
2006/07	11966	9348	2618

While overall imports are necessitated, there would be regional imbalances wherein, the western region has surplus availability of LPG while other regions are in deficit (See Table 14.2). The Western LPG market is covered in greater detail in Annexure 14.2.

Table 14.2 Projected demand-supply balance in the western region (TMT)

Year	Demand	Supply	Surplus
2001/02	2142	4394	2252
2002/03	2334	4302	1968
2003/04	2534	4734	2200
2004/05	2742	4882	2140
2005/06	2958	4845	1887
2006/07	3182	6076	2894

Options for ONGC

The western surplus has a significant bearing on the marketing options for ONGC. ONGC's fractionators, located in the West, contribute to this surplus. Excess production in the west, would have to be moved to other regions. LPG production from ONGC's fractionators (Table 14.3), accounts for about 27% of the total LPG availability in the West.

Table 14.3 LPG production profile from ONGC's fractionators (TMT)

Fractionator	2002/03	2003/04	2004/05	2005/06	2006/07
Uran	408	419	397	371	352
Hazira	546	527	488	488	488
Ankaleshwar	10	9	8	7	6
Gandhar	49	47	43	33	27
Total	1013	1002	936	899	873

Output from ONGC's fractionators is, however, expected to decline in the future. Any strategy adopted must be cognizant of this fact. The alternatives available to ONGC are:

- Direct marketing of LPG by ONGC
- Exports
- Sales to parallel marketers
- Renegotiate sales of LPG to oil marketing companies (OMCs) on commercial terms

Direct Marketing

Bulk versus bottled sales

LPG is primarily marketed either in the form of bulk sales to industrial/commercial users or retail sales in the form of bottled LPG. As a marketing option, bulk sales score over retail as they entail substantially lower investments as compared to retail which requires investments in bottling plants, dealerships, distribution, etc. The demand for bulk sales for LPG in the country, however, is fairly limited. LPG requirements by the total industrial/commercial sectors add up to 638 TMT only. In contrast, ONGC's current LPG production aggregates 1,214 TMT. Thus, even if ONGC were to capture the entire industrial/commercial market in the country, the total offtake would account for only half of its production, necessitating retail sales of the remaining.

A more realistic scenario indicates even lower possibilities for bulk sales by ONGC. There is a spatial dimension to the bulk LPG market, which cannot be ignored. With ONGC's production facilities located in the western part of the country, it is unlikely that it would be a competitive supplier throughout the

country as freight costs are substantial. ONGC's target markets are also, thus, likely to be limited to the western region only. The western region, however, accounts for only a fifth^a of the total bulk LPG market in the country. The effective bulk LPG demand for ONGC is thus likely to be only 120 TMT, representing only 10% of the LPG production by ONGC. The remaining would have to be marketed in bottled form.

Economics of bottling

It is inevitable, hence, that in case ONGC chooses to engage into direct marketing of LPG, it would have to opt for retail marketing. Bottled LPG from ONGC would have to be competitive with sales from established players in the industry – IOC, BPC and HPC. The price of bottled LPG offered by ONGC, thus, would have to be at least at par with that offered by other OMCs. It may be noted that setting up of a bottling plant entails substantial investments. While other OMCs have already recovered their investments in LPG marketing infrastructure by and large, ONGC would have to recover its investments from prices dictated by the OMCs.

At present, LPG prices are controlled by the Government through the APM (Administered Pricing Mechanism). Under the APM, OMCs charge Rs 970/MT towards filling (bottling) expenses. The APM, however, is scheduled to be dismantled by April 2002, the intended date for full deregulation of the oil industry. Since OMCs are already operating profitably at current price levels, it may be expected that a similar charge would be retained in the post-deregulation as well. On the upside, filling charges may be expected to be at most at Rs 1,346/MT as estimated by the Expert Technical Group (ETG).

These, however, turn out to be substantially lower than the costs of constructing and operating new bottling plants. Capital costs for a bottling plant vary depending on the degree of complexity in the plant, extent of automation, carousal size – 12/24 stations, volumes to be handled, etc. For instance, while IOC's 78 TMT plant at Shimoga in Karnataka entailed a total investment of Rs 60 crores, BPC's Loni plant in Uttar Pradesh also had similar order of investment, Rs 55 crores, although the plants capacity was only 44 TMT.

Typically, however, investments for a bottling plant of 44 TMT could be pegged at Rs 30 crores. Inclusive of operating costs, filling charges for such an investment are expected to be about Rs 2,091/MT (Annexure 14.3). It is evident that if ONGC's filling charges are twice as much as those of other OMCs, it is

^a Bulk PSU LPG sales in 1999/00 in the Western region of 100 TMT accounted for 19% of the total bulk LPG sales of 534 TMT

unlikely that bottled LPG from ONGC would be competitive to that from other OMCs. Even if OMCs hike filling charges to those levels as estimated by the ETG, filling costs for ONGC would be about 55% more than those for other OMCs.

In summary, if ONGC chooses to engage into direct marketing of its LPG, it would have to:

- Take established OMCs head-on to carve a market share for itself
- Invest in bottling infrastructure as scope for bulk marketing is fairly limited
- Match its prices, for both bulk and bottled LPG, to those of other OMCs

In doing so, it is likely that ONGC would be out priced by its competitors. In addition, direct marketing would require ONGC to commit itself to brand-building. Marketing/brand building expenses can be substantial and it would not be prudent for a company to invest in brand-building for a product, the production of which is expected to decline in the future.

Exports

With domestic LPG demand exceeding supply, large-scale exports have never really been an option as far as LPG is concerned. In 1999/00, while 1.4 MMT of LPG was imported, exports aggregated 31 TMT only. The limited exports undertaken are primarily those by IOC to Nepal.

The preceding analysis highlights the fact that LPG is likely to be in deficit over the Tenth Plan period as well, necessitating large scale LPG imports. In such a scenario, exports do not appear to be an attractive option, particularly given the low realisations from exports as against to domestic prices at import parity. Table 14.4 presents the indicative import parity price for LPG on the Indian west coast in line with Saudi Aramco's postings for Butane/Propane for December 2001. The same is contrasted against likely export realisations benchmarked against Japanese cif prices for Butane/Propane in December 2001 in Table 14.5.

Table 14.4 Indicative import parity price for LPG: December 2001

Parameter	Units	Value
Fob: Mid East Gulf	\$/MT	210
Load port charges	\$/MT	1
Freight	\$/MT	35
C&F	Rs/MT	11808
Insurance @ 0.3%	Rs/MT	35
Ocean Loss @ 0.3%	Rs/MT	35
Cif	Rs/MT	11879
Landing charges @ 1%	Rs/MT	119
Cif + Landing charges	Rs/MT	11998
Customs Duty @ 10%	Rs/MT	1200
LC Charges @ 0.3%	Rs/MT	36
Port dues	Rs/MT	100
Import Parity Price	Rs/MT	13333

Table 14.5 Likely export realisations. December 2001

Parameter	Units	Value
Japanese Cif	\$/MT	225
Less: Freight	\$/MT	35
Less: Ocean Loss, insurance, etc	\$/MT	11
Fob	\$/MT	179
Fob	Rs/MT	8573
Less: Port dues	Rs/MT	100
Export realisation	Rs/MT	8473

As is evident from the above, export realisations are likely to be substantially lower (about Rs 5,000/MT). In addition, ONGC would have to invest in new infrastructure to export LPG - a dedicated pipeline to the port, storage facilities at the port, loading arrangements, cryogenic facilities for transportation, etc. The costs incurred in development of such facilities would have to be borne out of the export earnings. The net realisation from exports is, thus, likely to further reduced.

The declining production of LPG again becomes a critical issue while considering the viability of exports. A buyer, in general, would tend to lock on to a secure supply source, i.e., where availability is not an issue. In case of exports by ONGC, the company would have to look for buyers who are willing to contract reducing volumes.

In summary, LPG exports do not appear to be a lucrative option as,

- There are likely to be few buyers willing to contract for reducing volumes
- Export realisations would be much lower than domestic prices (likely to be at import parity)
- Investments would be required to facilitate exports

Sales to parallel marketers

The possibilities of sales to parallel marketers are also bleak. The parallel market trade is fairly limited, with total imports by parallel marketers aggregating only 178 TMT in 2000/01. The trade in the western region is further limited and distributed amongst a number of players - Bharat-Shell, SHV, Hindustan-Domestic Oil & Gas Co Ltd., and Reliance.

The key reason for limited operations by parallel marketers has been their cost disadvantage against public sector (PSU) OMCs. Parallel marketers have had to compete with PSU sales, subsidised by the Government through the oil pool account. As a result, over the years parallel marketers have suffered

substantial losses and are now threatening to pull out^a of the business, unless the subsidies are extended to their operations as well. Companies like Bharat Shell have put a freeze on further investments in India and have decided to divert funds earmarked for Indian markets to other destinations like China.

The ensuing scenario precludes any possibilities of marketing tie-ups with parallel marketers.

Commercial agreements with OMCs

Reviewing the options available to ONGC, it appears that direct marketing and exports are not likely to be lucrative strategies for the company. Given the market scenario, wherein retail bottled LPG sales constitute the bulk of the market, ONGC's dependence on OMC's for assured offtake of its production seems inevitable. With 6,000 plus distributors across the country amongst the OMCs, they have an established delivery chain to reach out to consumers. In contrast, the ONGC, till date, has solely been a producer only, isolated from the markets and consumers. With ONGC's core competence in production, it would be prudent for ONGC to synergise its operations with OMC's, rather than competing with them for a share in the retail business.

The prevailing mechanism

Current marketing arrangements for LPG produced by ONGC are also via the retail networks of OMCs. There are dedicated pipeline links from ONGC's production sites to bottling plants of OMCs:

- Uran: Pipelines to BPC's bottling plants and the BPC/HPC refineries
- Hazira: Pipeline to IOC's bottling plant
- Ankleshwar: Pipeline to HPC's bottling plant

At Gandhar, while there is no dedicated pipeline for evacuation, IOC's neighbouring bottling plant is fed through tanker trucks. The bottling capacities of OMCs at these sites, however, aggregates to 288 TMT only (Table 14.6).

Table 14.6 Bottling capacities of OMCs at ONGC's production sites (TMT)

Site	OMC	Bottling Capacity
Uran	BPC	132
Hazira	IOC	44
Ankaleshwar	HPC	44
Gandhar	IOC	68
Total		288

^a "LPG MNCs threaten to exit, seek subsidies", Business Standard, 18th August 2001

The remaining is distributed by OMCs across their bottling plants in Western and Northern India in line with the monthly supply plan prepared by the Oil Co-ordination Committee (OCC).

The OCC also works out the price applicable for sales to OMCs. LPG prices continue to be administered through the oil pool account. Each month, the OCC works out the fractionator gate price for LPG produced from all fractionators (and refineries as well). The oil marketing companies pick up the same from refineries and fractionators at the Tariff Adjusted Import Parity Prices (TAIPP), also worked out by the OCC. The difference between the fractionator gate prices and the TAIPP is surrendered or claimed, as the case may be. **It may be noted that, as of now, there are no legally binding commercial agreements behind these exchanges.**

Post-deregulation scenario

Full deregulation of the oil sector is expected by April 2002. Post-deregulation, while the APM would be dismantled, the Government has decided to continue reduced subsidies on LPG and Kerosene. These would be brought out of the ambit of the oil pool account and transferred to the fiscal budget. The system of fixing the TAIPP for controlled products is, thus, likely to be discontinued and refineries/fractionators would sell their products to OMCs on commercial terms.

Post deregulation, product pricing would be governed by market forces. There would be no Government control on prices and OMCs would be free to charge appropriate prices. Since LPG is likely to remain in deficit, a scenario wherein domestic requirements would be met with imports at the margin, market prices for LPG, would in general, reflect product prices in international markets, i.e., import parity. As marketing companies, OMCs would try to procure LPG from producers at the lowest possible prices. However, ONGC as a producer should aim to receive prices as close to as possible to the import parity prices for LPG. Current fractionator gate prices received by ONGC, in fact, are far lower than the actual import parity prices (Table 14.7).

Table 14.7 Current realisation from LPG sales vs. import parity prices: Apr'2001 - Oct'2001 (Rs/MT)

Month	Fractionator Gate Price [*]	Import Parity Price [#]	Difference
Apr	12463	18838	-34%
May	9416	15879	-41%
Jun	8374	15610	-46%
Jul	9303	15879	-41%
Aug	9523	15476	-38%
Sep	8077	14265	-43%
Oct	7263	13996	-48%

^{*} Data furnished by ONGC

[#] As per price build up indicated in Table 14.10

On an average, the current price realised by ONGC on LPG sales is about 40% lower than the prevailing import parity price.

Recommended strategy for ONGC

Post-deregulation, ONGC should, thus, aim,

- a) To convert current marketing arrangements into legally binding commercial agreements
- b) To seek ***near import parity*** prices for LPG sold to OMCs

ONGC may seek take or pay agreements or a cut in marketing margins from OMCs, but it is likely to be on a weak wicket to do so. It must target near import parity prices, i.e., sales at a slight discount to the import parity price. The reasoning for the above is elaborated below.

Take or pay

ONGC could also explore the possibilities of entering into take or pay agreements with OMCs. Under such a system ONGC would be committed to provide specified volumes, while OMC would be committed to uplift the same. Failure by OMCs to do so would attract financial penalties.

It may be noted, however, that the ONGC is likely to be on a lean wicket as far as negotiating take or pay clauses is concerned. ONGC would be able to enforce take or pay obligations only if OMCs lack alternative supply options. A review of the demand in the western region indicates that the OMCs could, more or less, meet their requirements without access to LPG from fractionators (Table 14.8).

Table 14.8 Fall back arrangements for LPG supplies by OMCs

Supply Source	Availability	Bottling Plants	Capacity
RPL	1901	Rajkot	44
		Bhavnagar	44
		North (Jamnagar-Loni Pipeline)	1700
		Sub-Total	1788
		Surplus	113
Koyali	313	Ankaleshwar	44
		Hazira	44
		Gandhar	68
		Ahmedabad	66
		Gandhinagar	26
		Hanyala	34
		Sub-Total	282
		Surplus	31
HPC/BPC Refineries	497	Uran	132
		Mumbai	122
		Usar	109

Supply Source	Availability	Bottling Plants	Capacity
		Jalgaon	44
		Aurangabad	44
		Chandrapur	44
		Khapn	44
		Chakan	44
		Pune	22
		Manmad	34
		Akola	44
		Sub-Total	683
		Surplus	-186
Ratnagin (Imports)	200	Miraj	44
		Solapur	44
		Satara	22
		Sub-Total	110
		Surplus	90

RPL's production can be used for the Rajkot and Bhavnagar markets in Gujarat, while the rest can be pumped into the Jamnagar-Loni pipeline for northern markets. The remaining markets in Gujarat can be easily fed from the Koyali refinery. Likewise, the markets in Maharashtra can be fed from the Mumbai refineries, though some deficit remains. However, the import facility at Ratnagiri could be employed to bridge some of this gap and meet the demand in Southern Maharashtra. As far as additional demand in northern markets is concerned, imports up to 600 TMT could be facilitated at Kandla.

On the other hand, if OMCs fail to lift supplies from ONGC, ONGC could have a containment problem at hand. Since storage capacities at production sites exceed daily production levels, ONGC would be able to tide over short-run upliftment embargoes. The maximum cover, 7 days, is available at Hazira where storage capacity aggregates 22,500 cubic meters as against a daily production of 3,000 cubic meters of LPG. Beyond this, however, if OMCs fail to lift LPG, ONGC may have to shutdown its production. This would also hamper production of other value-added products like naphtha and Kersoene.

Sharing of margins

Under the APM, OMC's enjoy a marketing margin of Rs 922/MT on domestic LPG sales. As in the case of fractionator/refinery gate prices, the marketing margin too is fixed by the OCC. Margins are higher for sales to industrial / commercial consumers as prices for them are not administered.

Again, while ONGC may wish to get a share of the marketing margin, it is likely to be on a weak bargaining chip to do so. As discussed above, the OMCs do have fall-back arrangements for alternative supplies. As it is, the western region

is surplus with LPG, and the OMCs have to evacuate this surplus, including ONGC's output, to the northern markets. Under the emergent scenario, it may not be possible for ONGC to press for a cut in marketing margins of OMCs.

Pricing: Discounts to import parity

It is apparent from the above, that continuing current marketing arrangements with OMCs would be the best option for ONGC. The OMCs, however, do have fall back options to bring in imports at the margin. Considering the import parity price for LPG, for the first seven months of the current fiscal, at Rs 15,706/MT (Table 14.7), the landed cost^a of imported LPG at a northern market for OMCs, say, the bottling plant at Madanpur Khader (Delhi) is estimated at Rs 17,098/MT.

Current railway freight^b for moving the same from Hazira, on the other hand is Rs 1,147/MT. Thus, if ONGC offers LPG for Delhi from Hazira at Rs 15,952/MT (Rs 17,098/MT less Rs 1,147/MT), OMCs may well resort to imports and curtail upliftment from ONGC. Likewise, rail freight from Uran^c to Delhi is Rs 1,621/MT. OMCs would not be keen to pick up LPG from Uran for ex-Uran prices higher than Rs 15,478/MT (Rs 17,098/MT less Rs 1,621/MT).

If, on the other hand, ONGC were to offer the LPG at a slight discount to the import parity price, LPG from its fractionators would be readily sought by OMCs.

For instance, if ONGC offers LPG at a 5% discount (say) to the import parity price, the contract price for OMCs would be lower by Rs 855/MT as against that in the case of LPG imports. On an annualised basis, this discount would affect savings in procurement in excess of Rs 100 crores.

For ONGC, even with the 5% discount that assures full evacuation of its output, realisations would be substantially higher than what it receives today. As against the average import parity price of Rs 15,706/MT, the average fractionator gate price set by the OCC for the same period was Rs 9,203/MT (Table 14.7). Even if ONGC offers LPG at a 5% discount to the import parity price, its realisation would be higher by Rs 5,895/MT at Hazira and Rs 5,420/MT at Uran. On an annualised basis, the net gain for ONGC would be about Rs 650 crores (Rs 360 crores at Hazira and Rs 290 crores at Uran).

^a Import parity price at Kandla, plus pipeline freight from Kandla to Delhi via the Kandla/Jamnagar-Loni pipeline.

Freight considered is that as recommended by the Expert Technical Group for new pipelines, i.e., Rs 1.13/MT/Km

^b Rail distance from Hazira to Delhi is 869 kms. The applicable railway freight for a train load of LPG (general classification 220) for the distance slab 876 – 900 kms is Rs 114.64 per quintal

^c Full rail loading facilities available at BPC's bottling plant at Uran

Concluding remarks

While deregulation of the oil industry per se provides opportunities for ONGC, the options available to ONGC do not appear to be lucrative. Direct marketing of LPG would pit ONGC against established oil marketing companies. Under the resultant scenario, ONGC would have to necessarily invest in bottling infrastructure. Such investments, are likely to render ONGC uncompetitive to established players in the industry.

Exports too turn out to be unattractive, with realisations far below those in the domestic market which are likely to be at import parity. Again, exports would require investments in evacuation and port infrastructure, which further reduce net realisations from exports. Sales to parallel marketers are also ruled out given their limited market share. Additionally, possibilities of parallel marketers winding up their operations is not precluded, given their precarious financial position.

Given the market scenario, it is recommended that ONGC should opt for continuing current marketing arrangements with OMCs. However, post deregulation, these arrangements should be backed by commercial agreements, clearly specifying delivery points, volumes, prices, credit terms, etc.

There is a huge difference between the current price realised by ONGC and the prevailing import parity prices for LPG. ONGC should aggressively negotiate to hike its realisation to near import parity levels. Slight discounts by ONGC vis-à-vis the import parity price would assure 100% offtake of its production by OMCs. Even with discounts to import parity prices, the net gain for ONGC would be substantial, enhancing its profitability considerably.

Introduction

Naphtha, a light distillate, is used in power generation, urea production and petrochemical plants for different purposes. In power generation, it is used as a fuel; in urea production, it is used primarily as a feedstock to produce ammonia but is used as a fuel also and in petrochemical plant, it is used to extract other chemicals like benzene etc. Gas can replace naphtha in power generation and fertiliser production. Thus, apart from refineries, ONGC's naphtha faces competition from domestic gas and LNG. It is a deregulated commodity and can be sold freely domestically or can be exported. The naphtha market characteristics have been detailed in Annexure 15.1.

Though there are net imports of naphtha in the country, as shown in table 15.1, the figures disguise the fact that most of these imports are of petrochemical grade naphtha which is not comparable with naphtha produced in the country.

Table 15.1 Naphtha imports and exports (TMT)

	1996/97	1997/98	1998/99	1999/00	2000/01
Imports	15	1874	2407	1917	3165
Public Sector			168	230	340
Private Sector	15	1874	2239	1687	2825
Exports	2589	2048	720	583	2882
Net Imports	-2574	-174	1687	1334	283

Source. OCC

If we exclude all imports of naphtha on the basis that these are of petrochemical grade naphtha and hence are not comparable with ONGC's naphtha and simultaneously exclude the production from Reliance refinery at Jamnagar on the basis that its naphtha production is exported in a swap agreement, we have the following demand supply outlook for naphtha. The detailed demand supply outlook has been given in Annexure 15.2.

Table 15.2 Naphtha demand supply gap (TMT)

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
Demand	8009	8104	7756	7915	6552	5777
Supply	9355	9598	9453	10291	10273	10775
Surplus	1346	1494	1697	2376	3721	4998

As this table shows, there is a projected surplus of 4.9 million tonnes in the year 2006/7.

As ONGC's production is concentrated in the West, the demand supply scenario emerging in the region will have an important bearing on the marketing options.

The following table shows the demand supply situation for the Western region, given in more details in Annexure-15.2.

Table 15.3 Regional Naphtha demand supply gap (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	487	431	616	897	1554	1462

This projected surplus in the western region has to be kept in mind while deciding on marketing strategy.

The projected production of ONGC in the western region is shown below.

Table 15.4 Projected ONGC's production (TMT)

Location	Product	2002-03	2003-04	2004-05	2005-06	2006-07
URAN	Naphtha/NGL	234	243	232	220	212
Hazira	ARN	1182	739	653	654	656
	Light Naphtha	0	244	244	244	244
Ankleshwar	NGL	9	8	7	6	5
Gandhar	Naphtha	31	29	27	21	17
TOTAL		1482	1290	1189	1171	1160

Source: ONGC

Thus, 80% of the western region surplus can be accounted for by ONGC's production. Given the fact that IOC have a strong market presence in the western region (Annexure –15.1), it will be difficult for ONGC to dispose off its production.

Current status

Hazira

From Hazira, majority of the product is being transferred to OMCs, primarily IOC and HPC, either through pipeline or through rail/road network. However,

since ONGC started facing some problems in naphtha offtake by OMCs, it decided to sell naphtha directly. Thus, ONGC is also selling the product directly to Reliance Petrochemicals, Essar Steel and Essar Power. But these are spot sales invited by ONGC as and when the naphtha storage tanks threaten to overflow.

Table 15.5 Naphtha sales by ONGC (TMT)

	1 st week	2 nd Week	3 rd Week	4 th Week	Total
IOCL	11543	2574	15414	0	29531
HPCL	13826	13091	8658	10741	46318
ESSAR POWER	0	0	0	0	0
RELIANCE	0	0	29963	0	29963
Total	25369	15666	54036	10741	105815

Source: ONGC, Note: Individual figures may not add to the total due to rounding off

The following table shows the average basic and assessable value of naphtha for the past three years. These values are decided for a particular payment cycle which varies from OMC to OMC.

Table 15.6 Assessable vs. Basic value (Rs/MT)

Period	1/4/01 - 15/10/01	3/5/00 - 31/3/01	1/4/99 - 31/3/00
Assessable value	12566.00	13402.17	9560.00
Basic value	11499.50	12010.00	8608.93
Margin	1066.5	1392.17	951.07

Source: ONGC

The basic value is the Refinery Transfer Price (RTP) fixed on import parity basis by the OMCs from time to time. This is the price at which the refineries transfer naphtha to the marketing company. The assessable value is the price at which the marketing company sells naphtha to the final consumer. The assessable value is a buildup on the RTP and includes, inter alia, marketing cost of Rs 300/MT, some percentage of marketing margin, and a price-balancing factor. The assessable value is exclusive of all the sales tax and the state surcharges and the freight to the final consumer. Thus effectively, the difference between the basic value and the assessable value is the overall marketing margin OMCs are earning on ONGC's naphtha. This margin is fluctuating over time because of the fact that the marketing margin included in the assessable value is a percentage on the basic value and secondly, the OMCs are selling naphtha to the fertiliser plants at low margins.

Due to this margin, if ONGC were to sell naphtha directly, it can aim to get a price better than the basic price it is getting from OMCs.

However, as the following table shows, it receives even less when it sells naphtha directly to the domestic consumers.

Table 15.7 Realisation from direct selling (Rs/MT)

Consumers	Price for the period 3/5/00 - 31/3/01
Essar Power	11893.87
Essar Steel	10321.19
IDPC	9267.96

Source. ONGC

The low realisation is due to the fact that these are spot transactions and hence the leverage is with the buyers since ONGC has got no choice but to sell its naphtha.

Apart from direct marketing, ONGC is also exporting some naphtha, primarily to Japan but only through IOC. In the period May 2000 to February 2001, ONGC exported about 300 TMT tonnes of naphtha with average realisation of 9820 Rs/MT, which is even lower than the spot sales to domestic consumers.

However, the billing rate for naphtha as realised over this period was Rs 11995.60/MT which means that various expenses involved in exports like SBM charges, pipeline charges, and canalising commission reduced the net realisation from exports to Rs 9820/MT.

Uran

The situation is almost the same at Uran with ONGC forced to export its naphtha from the Pir Pau jetty due to unsatisfactory upliftment of naphtha by the OMCs. Naphtha from this location is exported through HPCL and is sold on spot basis, which is more or less a distress cargo in the international market and hence the realisation is low.

Gandhar

From Gandhar, ONGC is selling all the naphtha to BPCL which is further selling it to GPCL Dahej which is using it as fuel. The transfer is through road tankers.

Ankleshwar

Naphtha from Ankleshwar is sold through BPCL and the mode of transportation is again road tankers.

Options for ONGC

ONGC has got the following options for selling its naphtha-

1. Renegotiate with OMCs.
2. Sell naphtha directly to the customers.
3. Vertical diversification.
4. Bypassing naphtha production.
5. Export the product.

Each of this option has certain benefits and costs that are analysed below.

1. *Renegotiate with OMCs*

Renegotiations with OMCs can be done on two terms. Firstly, it can be for a share in the marketing margin earned by the OMCs on selling ONGC's naphtha. Secondly, it can be a long-term purchase contract with one or more OMCs for the minimum quantity that ONGC can produce in the long term.

The main benefit of renegotiating for a share in marketing margin is that this will result in higher than current price realisation for its naphtha without any concomitant increase in costs. On the other hand, this may increase the offtake uncertainty since OMCs will get more reluctant to sell ONGC's naphtha, especially in the view of surplus situation in the country.

The main benefit of entering into long-term purchase contract with OMCs is avoidance of extra administrative costs of selling naphtha directly. Moreover, there will be no offtake uncertainty in that event and would avoid sales on distress on low prices. However, this may not fetch ONGC the best price as given the irregular pattern in the upliftment by OMCs, it may be difficult for ONGC to induce the OMCs to enter into a take-or-pay contract unless there is some price incentive.

2. *Selling naphtha directly*

As ONGC's naphtha production is concentrated in the western region, it is reasonable to assume that it can sell directly to the consumers in this region only since carrying it further away would render the product uncompetitive with respect to naphtha production in that region.

The main benefit of selling directly under long term contracts is reduced uncertainty of offtake by OMCs and hence reduced distress sales.

On the other hand, it will raise the administrative costs for ONGC since it has to enter into contract with each and every consumer separately.

For the month of October 2001, ONGC Hazira sold around 76 TMT of naphtha to IOC and HPCL and around 30 TMT directly to Reliance Industries as shown in the table 15.5.

Sales to direct consumers like Reliance and Essar are more of a distress sale whenever IOC fails to uplift naphtha in adequate quantity and as the tables 15.6 & 15.7 show, the realisations from these sales has been lower than those from sales to OMCs. So technically speaking, ONGC is still dependent on OMCs for naphtha upliftment at best prices.

The following table shows the comparative quality of naphtha produced by ONGC and by IOC.

Table 15.8 Quality comparisons

Parameters	Unit	Values for ONGC	Values for IOC
Distillation FBP, Max	Deg C	161-175 (Max 180)	180
Aromatics Max	% Vol	10-12 (Max 15)	15
Olefins Max	% Vol	1	1.5
Density at 15 Deg C	Gm/ml	0.73 Max	0.66-0.75
Gross Calorific Value	Kcal/kg	11280 Min	10200

As this table shows, there is not much difference between the quality of naphtha produced by ONGC and IOC except the Gross Calorific Value, which is higher for ONGC's naphtha. But this is too important to tilt the scales in the favour of ONGC and allow it to carve a market for its naphtha.

It is also possible that long-term contracts, not nearing their maturity date, are currently in force between the OMCs and consumers in which case it would be difficult for ONGC to break the existing bonds.

Pricing issues

Impact of LNG

The impact of LNG would be more pronounced on the prices of naphtha because gas can replace naphtha in many applications, especially fertiliser production and power generation. Shell is planning a LNG terminal at Hazira and Petronet is building a LNG terminal at Dahej. Thus, within few years, there is a possibility of LNG flooding the Western sector. In such a case, the naphtha upliftment will fall and so will the prices.

Impact on Fertiliser sector

The consumption of gas by the fertiliser sector was 7.625 billion cubic metres in 1996-97 and is expected to reach 20 billion tonnes in 2001-02^a. With the coming

^a Fertiliser Pricing Policy, Department of fertiliser, March 1998

of LNG, almost all the fertiliser units are expected to shift to gas. This is due to some intrinsic benefits of using gas for urea production, as shown in the table below:

Table 15.9 Comparison among various feedstocks for producing urea

Feedstock	Investment (Rs. crores)	Energy Consumption Gcal/T of urea	Feedstock				Feedstock Prices	
			Qty/T of urea	Rs/Unit			Rs/MMBtu	Rs/T of urea
Indigenous gas	1425	5.07	549 SM3	3936/1000 SM3			58.35	2161
LNG	1425	5.07	548 SM3	6666/1000 SM3			162.54	3385
Naphtha	1474	5.10	0.483/Te	8483/Te			187.60	4097
Fuel Oil	1976	6.57	0.663/Te	5911/Te			125.52	3921

Source. Fertiliser Pricing Policy, Department of fertiliser, March 1998, page 42

As this table shows, the cost of feedstock per tonne of urea produced is higher in the case of naphtha than using gas and LNG. Moreover, the capital cost of setting up the new urea plant is also lower for a plant using gas/LNG than for a naphtha-based plant. With the costs of conversion of an existing naphtha based unit into a gas-based unit being negligible, one expects that the fertiliser plants in the country will shift to gas. And this fact is amply illustrated in the demand supply scenario built in Annexure-15.2 that shows a huge drop in naphtha demand after coming of LNG.

The landed cost of LNG is still indexed to crude oil prices. But there is a possibility that this may become weaker as the LNG market further develops. However, if we calculate the landed cost of LNG according to the current estimates, at crude price of \$18/bbl, the fob Middle East of LNG comes out to be 2.65\$/MMBtu. This fob price increase by 0.15\$/MMBtu for every 1\$ increase in crude oil price. Adding to it the transportation from Middle East to West Coast India and the relevant duties and regassification costs, the ex-Hazira cost of LNG comes out to be 3.68\$/MMBtu.

Imputed values methodology estimates that for naphtha price of Rs 7085/MT, the fertiliser plant will be indifferent between using naphtha and using gas landing at 3.68\$/MMBtu. This price however varies for variations in crude oil prices as shown in the table below. The detailed calculations are at Annexure 15.3.

Table 15.10 Imputed Values for naphtha versus LNG at Hazira

Crude oil price \$/bbl	Landed cost of gas at the plant \$/MMBtu	Imputed value of naphtha vs LNG Rs/MT	Import parity prices Rs/MT
18	3.68	7035	9260
22	4.33	8450	10960
25	4.82	9445	12235
28	5.31	10450	13510

The last column shows the average import parity prices, without any marketing cost charged by OMCs, at various crude oil prices at Hazira. The detailed buildup of the import parity prices is at table 15.11.

This table brings out that the imputed value for naphtha versus LNG is lower than the import parity price for naphtha. Thus, arrival of LNG will certainly reduce the naphtha realisation.

Impact on Power sector

During the past decade, government allowed Independent Power Producers (IPPs) to set up power plants based on liquid fuels like naphtha to limit the huge deficit in the power sector. This was also due to the fact that the plants based on naphtha or gas have a less gestation period. However, the state electricity boards were not in a position to pay for power generated from Naphtha, which due to its linkages with crude oil, proved to be too costly. Thus, many IPPs were shelved or were made on a dual fuel basis which means that they will shift to gas as soon as it is available. For example, Dabhol Power Company, which was using imported naphtha for its power plant, had the option to switch to gas when its LNG terminal is completed. Similarly, Essar Power is now mainly using gas and uses naphtha only as a swing fuel.

Thus, in the event of LNG coming to India, power generators will also shift to LNG.

Price war

One way to win away the existing customers of OMCs is to reduce the naphtha prices. But is this a feasible strategy in an oligopolistic market where the dominant player can undercut any price ONGC may set?

Recently, in response to the surplus situation in naphtha, the marketing committee of the OMCs changed the formula for setting the naphtha prices for fertiliser units that resulted in a reduction of prices by Rs 660 per tonne. Thus, in a collusive market, cutting prices is not an advisable strategy.

Cutting prices in a collusive market to undercut the market leader will result in a price war in which the company with longer staying power will survive. In this

context, both OMCs and ONGC are on equal footing since selling naphtha is not the main source of income for both and shutting down naphtha production is not an option for both. This would, however, result in revenue loss for both companies. Hence maintaining the current price structure is advantageous for ONGC.

Other possible pricing bases are energy equivalent pricing, calorific value equivalent pricing and yield equivalent pricing. Each of these pricing schemes price the product on the basis of its physical and quality characteristics and hence involve no element of price undercutting.

3. *Vertical diversification*

ONGC has got two options for vertical diversification. It can either acquire one of the two remaining PSU marketing companies or it can set up a downstream plant that uses naphtha as a raw material. Both these options are evaluated below with respect to naphtha upliftment.

Acquiring marketing PSU

The total all-India sales by BPCL and HPCL for the year 2000-01 were 1335.8 TMT and 1222.8 TMT^b respectively. Sales in the western region over the same period for BPCL and HPCL were 708.1 TMT and 806.7 TMT respectively. BPCL sold 440.2 TMT less whereas HPCL sold 203.6 TMT more than its naphtha production in the domestic market for the year 2000-01. Comparing these with the ONGC's production of 1688.7 TMT last year, it becomes clear that none of the PSUs will be able to sell entire ONGC's production in the domestic market. However, this strategy may be beneficial at the different production centres individually. At Gandhar, ONGC sells entire quantity to BPCL which sells it to GPCL Dahej. Thus, at Gandhar, acquiring BPCL may lead to internalising the marketing margins made on such sale. At Ankleshwar also, since the entire quantity goes to BPCL, acquiring BPCL may lead to higher price realisation. Naphtha at Uran is exported via BPCL and hence acquiring BPCL may internalise the canalising commission charged by BPCL on such exports. The situation is different at Hazira because the naphtha produced at Hazira is primarily sold through IOC and exports are undertaken directly by ONGC. Even if we assume that ONGC were to acquire HPCL and make up the 203.6 TMT deficit in its sales versus production from Hazira, it would amount to only 15.37% of Hazira production.

^b Source: IPR, March 2001

Thus, in so far as Hazira accounts for the majority of naphtha production by ONGC, acquiring any of these PSUs will not be of much economic significance at Hazira from the point of view of its impact on naphtha upliftment.

On the other hand, the costs for acquisition will be high because of competition between various players, both Indian and international.

Setting up a downstream plant

Industries using naphtha are power/steel, fertilizers, petrochemicals or processors.

For ONGC, the main benefits of setting up a plant that consumes naphtha are –

1. No costs associated with sale of naphtha.
2. No reliance on either OMCs or private sector for naphtha offtake.
3. No competition from LNG.

However, this option should be evaluated in the light of the fact that ONGC's naphtha production is projected to decline by about 22% over the four-year period from 2002/3 to 2006/7. Assuming the same declining growth rate, the naphtha production will decline to 498 TMT by 2019/20. 1.1 million tonnes of naphtha can support a power plant of 1115 MW or a fertilizer plant of 2 MMTPA. But with declining production, it will need to purchase 602 TMT of naphtha from outside in order to sustain these capacities in the year 2019/20. This will bring, apart from fuel costs, additional costs in the form of administrative and marketing costs.

Moreover, this strategy involves a high initial capital investment with long pay back period.

Then ONGC will have to enter into multiplicity of contracts with various stakeholders, which will again increase the costs.

This strategy would, therefore over a long term, mean a complete diversification of business activities of ONGC, the suitability of which depends on various factors other than mere profits.

Setting up a processor plant is another option. Processors are the small crackers that extract ethylene, butadiene etc. from naphtha. However, unlike power and fertiliser plants, there is no assured offtake for products produced by processor plant. They would have to be sold in the open market and would entail marketing costs. This would again mean a complete diversification of the activities of ONGC.

4. Bypassing the production of naphtha

At Hazira, naphtha is produced at two points: at Kerosene Recovery Unit and again when LPG and ARN are separated. The production of naphtha can be bypassed only at Kerosene Recovery Unit, which means that ONGC has to dispose off the NGL in addition to missing out on Superior Kerosene Oil (SKO) and Heavy Cut. While the whole economics of the process are difficult to work out given the limited scope of the study, it appears reasonable to conclude that this option would entail losses for ONGC apart from not solving the problem entirely.

5. Export the product

The benefits and costs of exporting naphtha can be estimated on the following grounds:

1. Projections for naphtha surplus

As shown in Annexure 15.2, naphtha is projected to be in surplus in all the regions of the country for the tenth plan period. This would make the task of finding buyers for naphtha very difficult. If ONGC were to export major part of its naphtha production, it need not rely on domestic offtake.

2. Reduction in domestic prices

Currently, naphtha is priced on import parity principle. But as naphtha becomes surplus in the country, prices may be set on export parity rather than import parity basis. As the tables below show, the export parity prices are lower than those based on import parity principle at various crude prices if sales are undertaken by OMCs.

Table 15.11 Import parity prices at Hazira

AG crude price	\$/bbl	22	25	28
Naphtha price*	\$/bbl	24	27	30
	\$/MT	223	250	278
Premium	\$/MT	5	5	5
Freight	\$/MT	5.5	5.5	5.5
Naphtha c&f	Rs/MT	10738	12002	13265
Ocean Loss (at 0.3%)	Rs/MT	32	36	40
Insurance (at 0.3%)	Rs/MT	32	36	40
LC Charges (at 0.3%)	Rs/MT	32	36	40
Port Charges	Rs/MT	125	125	125
Landed cost of naphtha at Hazira	Rs/MT	10960	12235	13510

* Naphtha prices have been regressed from FOB AG prices. Details are at Annexure 15.4.

Table 15.12 Export parity prices at Hazira

Elements	Unit			
AG FOB	\$/bbl	22	25	28
C&F Japan*	\$/MT	226	259	292
Less freight from West Coast India to Japan	\$/MT	17	17	17
FOB India	\$/MT	209	242	275
	Rs/MT	9613	11126	12640
Expenses				
SBM Charges	Rs/MT	500	500	500
Wharfage	Rs/MT	90	90	90
Pipeline charges	Rs/MT	24	24	24
Price realised at Hazira	Rs/MT	8999	10512	12026

*The C&F Japan prices have been regressed from the AG FOB prices. Details are at Annexure 15.5.

The expenses included in the above table are given by ONGC and it is assumed that any other company will also have to incur these expenses while exporting naphtha.

3. Strategic location of production facilities

About 80% of total ONGC naphtha production is based at Hazira. This is a coastal location and hence would realise the maximum by exporting the naphtha than the inland refineries which have to incur the cost of moving the naphtha from their refinery to the port.

4. No competition from OMCs

It will be very difficult for ONGC to compete with the OMCs due to that fact that they have an established marketing set up, backed up by huge volumes and have marketing contracts with major consumers. On the other hand, ONGC has a relatively small production, concentrated at one location and is projected to decline over time.

If ONGC exports its naphtha, it would be avoiding the competition from the OMCs.

5. Diseconomies in selling naphtha outside the western region

The OMCs have a presence in all the regions and hence can sell naphtha at a cheaper rate in the respective regions. On the other hand, ONGC's naphtha is concentrated at one location and moving it across to some other region will involve huge freights that will render ONGC's naphtha uncompetitive. However, there are two major drawbacks in relying on exports.

1. Excessive fluctuations in international naphtha prices

Naphtha prices in the international market are very volatile and complete reliance on exports will lead to excessive fluctuation in the earnings. This is undesirable for any organisation.

2. Declining production of naphtha

International buyers are more likely to enter into long-term contracts with suppliers who can assure them of supply security. ONGC's naphtha production is expected to decline in the coming decade and hence it would be difficult for it to enter into long term purchase contracts with international buyers.

Export market for ONGC

Examining the global market logistically, we find that ONGC can sell its naphtha in the Asia-Pacific region as carrying it to region farther away would render the naphtha costly and hence uncompetitive. We would therefore restrict the analysis of the global situation in naphtha demand and supply to the Asia-Pacific region.

The following table gives the country wise import demand for naphtha in the Asia-Pacific region.

Table 15.13 Country wise import demand (TMT)

Country	2001	2002	2005	2008
Australia	-	-	-	-
Brunei	-	-	-	-
China	79	475	1,305	5,655
Indonesia	633	554		
Japan	20,484	22,303	25,190	25,309
Malaysia	870	791	593	514
Philippines	-	-	-	-
Singapore	1,661	1,780	1,780	1,780
South Korea	12,654	12,971	13,050	13,168
Taiwan	1,898	1,582	2,254	2,294
Thailand	554	475	316	198
Other Asia	554	554	554	554
Total	39,386	41,483	45,041	49,470

Source. FACTS-EWCI

As this table shows, there is an import demand for around 49 million tonnes from the countries in the Asia-Pacific region. The bulk of the demand comes from Japan followed by South Korea. China is another market that will import increasing quantities of naphtha in the coming decade followed by Taiwan. Even Singapore has the demand that can absorb ONGC's production.

Realisation from exports

For the period May 2000 to February 2001, ONGC exported around 0.3 million tonnes of naphtha with billing rate of Rs 11995.60/MT (28.25 \$/bbl) which is very reasonable given that average Middle East naphtha fob in that period was 27.94 \$/bbl (11862.76 Rs/MT). However, due to various expenses, the net realisation over the period amounted to Rs 10080 per tonne without demurrage and canalising commission and Rs 9820/MT with demurrage and canalising commission.

This difference between the billing rate and the net realisation is due to various costs involved in exporting naphtha. The major variable costs are-

1. SBM Charges
2. Pipeline Charges
3. Wharfage

At various crude prices, the price realised by ONGC by exporting naphtha itself will be the export parity price as charged by OMCs, exclusive of marketing margin at Hazira, calculated in table 15.12.

The expenses considered exclude the canalising commission since recently ONGC has been exporting naphtha all by itself.

However, the price realised by exports can be increased if it is in a position to export a larger quantum of naphtha at one time due to longer notice period that can facilitate global tenders against the current practice of limited tenders and due to lower freight per MT for large vessels.

From Hazira, ONGC exports naphtha using the Reliance SBM that has the capacity to handle cargo upto 50,000 tonnes. To export a cargo of 50,000 tonnes at one go, a storage capacity of at least 75,000 tonnes is needed. The current total storage capacity for naphtha at Hazira is 99000 cubic meters which roughly translates into 72,000 tonnes but the operating capacity is only 57,000 tonnes. At any given time, one tank has to be kept for receipt of product from Kerosene Recovery Unit and one tank under despatch to local/rail fed consumers. This leaves only 38,000 tonnes of capacity that could be used for exporting naphtha. Thus, if ONGC has to increase the size of export parcels to 50,000 tonnes, it has to invest in the storage capacity at Hazira.

We can thus say that to become a serious player in the export market, ONGC must have adequate infrastructure at the export port, which is most likely to be Hazira. All this involves substantial time and cost and depends on the long-term production profile since infrastructural investments have a long pay-off period. Thus benefits and costs of investment in extra storage capacity must be weighed against each other in order to decide the desirability of extra storage.

Summary of options

Table 15.14 Current Status

	Price realisable (Rs/MT)	Quantity (tonnes/month)	Revenue (Rs million)
Sales to OMCs	12010	75849 [#]	910
Direct Sales	10494	29963 [#]	314
Exports through IOC	9820	30698 [*]	301

[#] For the month of October 2001^{*} For the period May 2000 to February 2001

Table 15.15 Summary of all options

Options	Benefits	Costs	Price realisable
1) Renegotiate with OMCs			
a) Share in marketing margin of OMCs	Higher price realisation.	Greater offtake uncertainty	Import/Export party price + Share in marketing margin
	No extra administrative efforts		
b) Long term purchase contract	No extra administrative efforts.	Lower price realisation	Lower than Import/Export party price
2) Sell naphtha directly through long term contracts			
	Reduced uncertainty of offtake	Increased administrative efforts.	<u>Non Availability of gas</u> Either import party price or export party price
		Direct competition with OMCs.	<u>Availability of gas</u> Imputed value of naphtha versus LNG at various locations.
3) Vertical Diversification			
a) Acquiring marketing company	Internalisation of full marketing margin.	Acquisition cost is likely to be high.	Import/Export party price + Full marketing margin
	Better export realisation at Uran.		
b) Setting up a plant using naphtha as a raw material	No need for any selling effort.	May have to buy naphtha some years down the line	NA
	No reliance on any OMC.	High initial capital investment.	
	No fear of reduction in naphtha prices due to LNG.	Extra administrative costs.	
		Multiplicity of contracts.	
4) Bypassing the naphtha production			
	No uncertainty regarding offtake.	Foregoing of margins on SKO and Heavy cut.	NA
		Have to sell NGL which may face the same problem.	

Options	Benefits	Costs Other costs associated with shutdown of operations.	Price realisable
5) <u>Export naphtha directly</u>	<p>No reliance on domestic market which is projected to be surplus in naphtha.</p> <p>No domestic spot sales on distress prices.</p> <p>Equal, if not more, than domestic realisation if the pricing is based on export parity prices</p> <p>Benefits of coastal location.</p> <p>Already has some experience in exports.</p> <p>Larger storage capacity will give bargaining power and reduce the spot sales.</p>	A larger storage capacity to the extent of 37,000 tonnes at the port may be required to have better realisation.	Export parity price

Concluding remarks

From the foregoing it is apparent that ONGC does not have too many options. Naphtha will continue to be surplus in the country; OMCs have their own sources to maintain while ONGC's naphtha production is located mainly in the western region and currently they have no marketing infrastructure.

The following table shows the prices Ex-Hazira, exclusive of any marketing margin, under different options at crude price of 25 \$/bbl, the expected long term average price of the OPEC's target crude oil price band of 22 to 28 \$/bbl.

Table 15.16 Comparison of prices

Pricing basis	Price (Rs/MT)
Import parity price	12235
Export parity price	10512
Imputed value of naphtha versus LNG	9445

The following strategy is therefore recommended:

- a) While ONGC may try and negotiate for a share of marketing margins it is unlikely that OMCs will agree as has been in the case in the past. However, the import parity price of Rs.12,235 per MT is an attractive one and ONGC should attempt to enter into long term contracts with the OMCs even if it has to give a small discount on this price.

- b) Acquisition of either BPCL or HPCL by ONGC will provide it the marketing infrastructure it needs and additional security for absorption of part of its production.
- c) To compete against LNG, not only ONGC but OMCs also will have to drop their prices substantially and depending on the supply demand balance this may be necessary if there are uncontainable surpluses.
- d) Export parity price on naphtha is about 14% lower than the import parity price but 10% higher than its imputed value vs. LNG. Therefore export of naphtha must always remain a second option if ONGC cannot realise the import parity price from OMCs or there is an uncontainable surplus. However to improve price realisations, ONGC must increase its storage capacity at Hazira (to load larger tanker parcel sizes) and use international trading instruments eg. options, hedging etc. to realise the best value for its export naphtha.

Introduction

The upstream oil sector of India is dominated by the two National Oil Companies – Oil and Natural Gas Corporation Limited and Oil India Limited, with a share of about 88% of country's present oil and gas production. While ONGC produces nearly 77% of indigenous crude oil and 82% of country's gas production, OIL's share of 10% of indigenous oil and 6% of gas production is confined mainly to its areas of operation in Assam, Arunachal Pradesh and Rajasthan. Oil and gas production by OIL in 1999-00 had been 3.3 MMT and 1729 MMCM respectively. Whereas oil and gas production by ONGC in the same year had been over 24 MMT and 23252 MMCM respectively.

The Xth Plan targets a domestic oil production of about 32 MMT by 2006/7, whereas the demand is expected to reach about 214 MMT. This gap of 85% is to be bridged by imports. ONGC targets an oil production of about 25 MMT by 2006/7. Any shortfall from domestic production targets will further increase the import dependence.

Demand/Supply forecasts

The share of oil in primary energy consumption has remained unchanged at 40% from 1990 to 2000. Almost all the regions have experienced a decline in the share of oil with the sole exception of Asia-Pacific. The largest decline has occurred in Former Soviet Union (FSU) where the share of oil declined from 30% to 19% followed by Middle East where the share declined from 64% to 54%. Asia-Pacific, on the other hand, has seen an increase in the share of oil from 37% to 41%.

According to World Energy Outlook (WEO) 2001, oil production is projected to increase to 87.9 million bbl per day by 2005 and to 97.4 million bbl per day by 2010. This implies an annual growth rate of 4% from 2000 to 2005. Likewise, consumption is projected to grow from 84.9 million barrels per day by 2005 to 94.9 million barrels per day by 2010.

Sweet crude demand/supply

North America, Europe and Asia-Pacific are projected to be net importers of crude oil while Middle East, Former Soviet Union, Africa and South and Central America are projected to be net exporters.

The following table shows the resulting demand supply balance of sweet crude for the coming decade.

Table 13.1 Demand-supply outlook for sweet crude (million tonnes)

	2005	2010
Demand	552	635
Supply	558	692
Net Surplus	6	58

Approach to marketing strategy

According to the existing Export-Import policy ONGC may not be in a position to export crude oil easily because of infrastructure constraints & also canalisation role still continue to be with IOC. Even if these constraints are tide over by ONGC, ONGC is not likely to get price better than the FOB price. This fact is known to most of the refineries and therefore they may be expecting that ONGC is not likely to enter international market for export of its crude.

Though ONGC may be expecting to move towards import parity prices while fixing its price for crude from April '02, it will not be easy for it to convince the refinery. Similarly refinery may not be justified in insisting that they will not pay more than what ONGC is presently getting from the OCC because ONGC will be committed to pay certain liabilities to the Government of India under various rule out of the amount which they get from refineries.

The various options for basic price that have been examined are:

Option A. ONGC receives fob of comparable international crude and pays central sales tax.

Option B. ONGC receives fob of comparable international crude but does not pay central sales tax

Option C. ONGC receives import parity price of comparable international crude and does not pay central sales tax

Option D. ONGC receives import parity price of comparable international crude and pays central sales tax.

In addition to deciding on the basic price for crude from the above mentioned four options, the report has also worked out estimates of premiums and

discounts applicable for different crudes. These premiums and discounts are calculated in view of the strengths and weaknesses of ONGC vis-à-vis refineries.

The resulting price structure for crude has been examined keeping in mind the exploration commitment of ONGC. As per the Annual Report of ONGC for 2000-01, it plans to invest Rs 47590 million to increase the reserves by 61.53 million tonnes in the next 20 years. This works out as \$ 2.3/bbl.

The results of the field wise price calculations are summarised below.

Field wise strategy

Bonbay High

BH crude is in a position to command a premium over and above the basic price from all the refineries. Applying this premium to all the four options for basic price for BH crude yields the following surplus for ONGC.

Table 13.2 Surplus for ONGC (\$/bbl)

Refinery	Option A	Option B	Option C	Option D
BPCL - Mumbai	1.86	2.37	5.44	4.81
HPCL - Mumbai	1.86	2.37	5.44	4.82
Koyali	1.40	1.91	4.98	4.34
Mathura	1.40	1.91	4.98	4.35
Panipat	1.41	1.92	4.99	4.36
Kochi	1.85	2.36	5.43	4.80
Vizag	1.88	2.38	5.45	4.82
MRPL	1.86	2.37	5.44	4.81
Chennai	1.88	2.38	5.45	4.82

Given the ONGC's exploration commitment of \$2.3/bbl, it seems that ONGC should negotiate for Option C. However it should accept no less than Option D which means that it should get the import parity price for BH and may pay the sales tax on behalf of the refineries.

Gujarat crudes

ONGC will probably have to give a discount to Koyali refinery for its North and South Gujarat crudes. Applying this discount to all the four options and deducting the various charges ONGC will have to pay, the following surpluses emerge.

Table 13.3 Surplus for ONGC (\$/bbl)

Refinery	Option A	Option B	Option C	Option D
Koyali	0.57	1.08	4.17	3.53

As this table shows, Option A and Option B are not sustainable for ONGC. Under Option D, given the exploration commitment of 2.3 \$/bbl, the net left is \$1.23/bbl which gives 34.8% return to ONGC which is very fair. Thus, ONGC should not accept anything less than Option D.

Cauvery basin

ONGC may not get the import parity price for its crude due to prohibitive costs of moving crude to alternate refineries. It may have to negotiate for FOB price only. Applying this discount to all the four options for setting the base price, the following surpluses emerge.

Table 13.4 Surplus for ONGC (\$/bbl)

Refinery	Option A	Option B
CBU	1.48	1.97

This table shows that if ONGC were to get the FOB price for its crude, then even if it gets the full premium as estimated above, it will find it difficult to generate enough surplus from this region.

Under Option B, the surplus left is \$ 1.97/bbl which is \$ 0.33/bbl less than the surplus of \$ 2.3/bbl required by ONGC to fund its exploration activities. Thus, ONGC should try to negotiate at least that price at which \$ 0.33/bbl higher than the price under Option D.

North Eastern crude

Given the fact that ONGC does not have any alternate option to sell its crude and given the fact that ONGC's crudes are not of international quality, it will be difficult for it to demand import parity price for its crude. The refineries are in a better position to source the crude either from OIL or take the imported crude and hence will not give import parity price to ONGC. Thus, out of the four pricing options mentioned earlier, only two are possible – those based on FOB.

The surplus left for ONGC under the two pricing options are shown below.

Table 13.5 Surplus for ONGC (\$/bbl)

Refinery	Option A	Option B
Barauni	1.26	1.77
BRPL	1.26	1.77
Guwahati	1.26	1.77
NRL	1.26	1.77
Digboi	1.26	1.77

This table shows that surplus generated in North East may not be enough if the pricing is done on FOB basis. However, if ONGC can negotiate for an additional \$ 0.53/bbl under Option B, it can make the required surplus of \$ 2.3/bbl.

Natural Gas

Domestic gas production at present is about 78 MMCMD. In contrast, gas demand estimations show that existing gas demand from power, fertiliser, industrial units like cement, paper and pulp and glass and captive generation is about 105.43 MMCMD. This is projected to increase to 136.93 MMCMD by 2006/7. Thus implying a widening gap between domestic gas supply and demand.

In India, 80% of the gas is consumed by power and fertiliser sectors. In future too these sectors will dominate the demand scenario. Bulk of the demand will be generated from the power sector which is projected to increase from 49.37 MMCMD at present to about 72 MMCMD by 2006/7.

Analysis of imputed values of gas reveal that at a gas price of \$4.5/MMBtu and \$3.5/MMBtu, gas demand in 2006 will be about 86 and 122 MMCMD respectively. The objective of the marketing strategy of gas is to maximise the netback to ONGC from selling gas.

Domestic gas price is expected to be linked to full parity with fuel oil in the near future. The gas price should get another boost in 2004 when LNG arrives at Gujarat.

The revision to full parity with fuel oil would not be effective unless the ceiling price is revised upward. ONGC should try to negotiate a high ceiling price. It would be more feasible for ONGC to negotiate a better fuel oil basket, choosing only low sulphur fuel oils, altering the weight in favour of low sulphur fuel oils in the basket and by changing fob prices to cif. So long as the ceiling price is acceptable, the consumers may be less sensitive to a higher price within the ceiling.

With the advent of LNG if domestic gas is pooled with LNG, the proportion of costly gas to domestic gas will have substantial impact on netbacks for ONGC. Thus ONGC must be fully involved in the price fixing exercise.

ONGC would be free to get a better price for gas from NELP blocks. When LNG becomes available, the price of this gas could be raised to import parity. However, most of this gas is expected to be found around Gujarat or Andhra Pradesh where gas-to-gas competition may keep the price down. In view of the possibility of increasing the gas price, it would be prudent not to sell this gas on long term contracts. At least, the price should be kept flexible.

Bulk selling to GAIL or other marketing agencies may be more feasible in cases where the marketing risk appears to be large. The price for bulk sales would be fuel oil linked. Again, the choice of fuel oils would be important, as would be the price ceiling or the linkage. These could vary between regions depending on the purchasing power of the customer. For gas sold to GAIL, prices are to be fixed by the government and likely to reach fuel oil parity, thus subject to variability depending on behaviour of crude oil prices. Where ONGC is free to price the gas a compromise acceptable to both the buyer and the seller would be a variable price subject to a floor and a ceiling. Generally, the ceiling would be dictated by the cost of alternative fuels to the buyer whereas the floor would be a function of the production cost.

Gas consumers in India may have difficulties in signing long term contracts with stiff take-or-pay provisions. Gas suppliers who depend on project finance for developing their fields may find such terms unavoidable. ONGC could offer more flexible contract conditions if that leads to a higher market share. In some cases, a similar advantage could be derived by offering Rupee prices in stead of Dollar denominated prices.

Value added products

Naphtha

From the discussion it is apparent that ONGC does not have too many options. Naphtha will continue to be surplus in the country; OMCs have their own sources to maintain while ONGC's naphtha production is located mainly in the western region and currently they have no marketing infrastructure.

The import parity price of Rs.12,235 per MT is an attractive one and ONGC should attempt to enter into long term contracts with the OMCs even if it has to give a small discount on this price. To compete against LNG, not only ONGC but OMCs also will have to drop their prices substantially and depending on the supply demand balance this may be necessary if there are uncontrollable surpluses.

Export parity price on naphtha is about 14% lower than the import parity price but 10% higher than its imputed value vs. LNG. Therefore export of naphtha must always remain a second option if ONGC cannot realise the import parity price from OMCs or there is an uncontrollable surplus.

LPG

Given the market scenario, it is recommended that ONGC should opt for continuing current marketing arrangements with OMCs. However, post

deregulation, these arrangements should be backed by commercial agreements, clearly specifying delivery points, volumes, prices, credit terms, etc.

There is a huge difference between the current price realised by ONGC and the prevailing import parity prices for LPG. ONGC should aggressively negotiate to hike its realisation to near import parity levels. Slight discounts by ONGC vis-à-vis the import parity price would assure 100% offtake of its production by OMCs. Even with discounts to import parity prices, the net gain for ONGC would be substantial, enhancing its profitability considerably.

Exhibit A - Scope of Study

Preamble

Over the decades, ONGC has been concentrating on production of crude, gas and value added products which were sold to the consumers specified by the Government/OCC at an administered price, generally cost plus. ONGC, therefore, could not develop capabilities for marketing and pricing of its products and also does not have detailed and reliable database required for commercial, marketing and pricing functions. However, the situation in respect of deregulated products has changed after MOP&NG's notification of November 1997. Situation is likely to change dramatically after March 2002 when other products of ONGC are likely to be deregulated. ONGC proposes to commission this study to prepare itself for the impending deregulation in April 2002.

Terms of Reference

(A) Crude oil

- (i) Benchmarking of crude oil produced by ONGC from its different fields to similar internationally traded crude.
- (ii) Demand of various types of crude by Indian refineries, crude indigenously available and crude to be imported.
- (iii) Study and analysis of global demand of crude and major supply sources in the world.
- (iv) Exploring options available to ONGC for export of crude, the procedural (both internal procedures, ONGC should adopt and external e.g., Government regulations and guidelines) requirements, demand – supply gaps, ports and transportation facilities available and bottlenecks.

(B) Natural Gas

- (i) Study the demand projections of bulk gas consumers in India.
- (ii) Examining the cost of next best alternative for gas in respect of important industry.
- (iii) Study LNG projects in India, as approved by the Government, including details of cost of imports, transportation and re- gasification and implication thereof on supply and pricing of gas of ONGC.

(C) Naphtha, LPG and Ethane – Propane

- (i) Study of domestic consumption, production and gap (import-export) trends in products with future projections.
- (ii) Study and analysis of global demand of these products and major supply sources in the world.
- (iii) Exploring options available to ONGC for marketing in India and export of these products, the procedural (both internal procedures, ONGC should adopt and external e.g., Government regulations and guidelines) requirements, demand-supply gaps, ports and transportation facilities available and bottlenecks.

(D) Contractual and other market related matters

- (i) Study on commercial practices of international trade consisting of Term, Spot, future and forward contracts, issue and evaluation of tenders and negotiations, etc.
- (ii) Study the feasibility of using hedging instruments by ONGC to minimize price volatility.
- (iii) Study the trading mechanism at commodity exchanges like IPE, NYMEX.
- (iv) Study and suggest various important clauses in supply contracts including ONGC' s strategy to negotiate better terms in the contract.

(E) General

- (i) Study of ONGC's organizational set up, existing marketing arrangements with bulk consumers/refiners to carry out SWOT analysis to ascertain the opportunities available and the related threat perceptions to decide the road map of ONGC in a long run under deregulated set up.
- (ii) Study the existing physical facilities (tankages, pipelines etc.) and need for additional facilities required to carry out its long term plan to market its petroleum products to bulk consumers including exports.
- (iii) Study and recommend changes required in the organizational structure of ONGC to carry out its marketing activities under deregulated scenario.

ANNEXURES

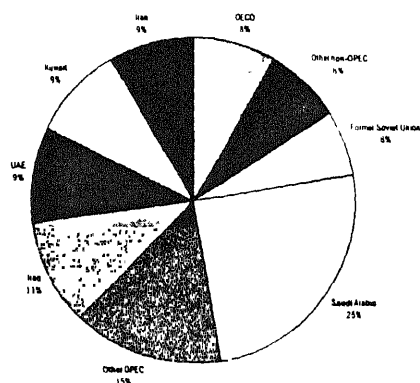
Annexures

Part-1

Annexure 2.1

World oil reserves and production

Distribution of oil reserves



Reserves and production of oil by region

	Proven Reserves, 2000 (Thousand million barrels)	Share	Production, 2000 (Thousand barrels/day)	Share	R/P ratio (Years)
North America	64.4	6.1	13905	18.1	13.8
S & C America	95.2	9.0	6835	1.5	39.1
Europe	19.1	1.9	6975	9.2	7.7
FSU	65.3	6.4	8035	11.0	22.7
Middle east	683.6	65.3	22990	31	83.2
Africa	74.8	7.1	7820	10.4	26.8
Asia Pacific	44	4.2	7970	10.6	15.6
World	1046.4	100	74510	100	39.9
Of which OECD	84.8	8.1	21545	28.1	11.5
OPEC	814.4	77.8	30825	41.5	74.3
Non-OPEC	166.7	15.9	35640	47.5	13.4

Annexure 2.2

Major oil producers and consumers (2000)

	Production (kb/d)	Share of total		Consumption (kb)	Share of total
Saudi Arabia	9145	12.3	USA	18745	25.4
USA	7745	10.4	Japan	5525	7.5
Russia	6535	8.8	China	4840	6.5
Iran	3770	5.1	Germany	2760	3.7
Mexico	3450	4.6	Russia	2475	3.3
Norway	3365	4.5	Korea	2200	3.0
China	3245	4.4	India	2070	3.0
Venezuela	3235	4.3	France	2010	2.7
Canada	2710	3.6	Italy	1945	2.6
U K	2660	3.6	Mexico	1840	2.5
Total World	74510	100	Total World	73905	100

Note. The difference between production and consumption totals is due to stock changes, consumption of non-petroleum additives, and disparities in definition, measurement and conversion of supply, demand data

Annexure 2.3

WEO projections of oil production and consumption by 2020

World oil production (reference case)

	2005	2010	2015	2020
	Production (million bbl/day)			
OPEC				
Persian Gulf				
Iran	4	4.3	4.6	4.8
Iraq	3.1	3.8	4.7	5.8
Kuwait	2.8	3.5	4.1	5
Qatar	0.5	0.6	0.7	0.7
Saudi Arabia	12.6	14.7	18.4	23.1
UAE	3	3.5	4.4	5.1
Total Persian Gulf	26	30.4	36.9	44.5
Other OPEC				
Algeria	1.9	2.1	2.3	2.5
Indonesia	1.5	1.5	1.5	1.5
Libya	2.1	2.5	2.8	3.2
Nigeria	2.8	3.2	4	4.7
Venezuela	4.2	4.6	5	6
Total Other OPEC	12.5	13.9	15.6	17.9
Total OPEC	38.5	44.3	52.5	62.4
Non-OPEC				
Industrialized				
United States	9	8.7	9	9.3
Canada	3	3.2	3.4	3.5
Mexico	4.1	4.2	4.4	4.4
Australia	0.8	0.8	0.8	0.8
North Sea	6.6	6.5	6.2	6
Other	0.8	0.8	0.8	0.7
Total Industrialized	24.3	24.2	24.6	24.7
Eurasia				
China	3.1	3.1	3	3
FSU	9.6	11.9	13.6	14.8
Eastern Europe	0.3	0.3	0.3	0.4
Total Eurasia	13	15.3	16.9	18.2
Other non-OPEC				
C&S America	4.2	4.8	5.5	6.4
Middle East	2.2	2.4	2.5	2.4
Africa	3.1	3.8	4.6	5.8
Asia	2.6	2.6	2.6	2.5
Total Other non-OPEC	12.1	13.6	15.2	17.1
Total Non-OPEC	49.4	53.1	56.7	60
Total World	87.9	97.4	109	122

World oil consumption (reference case)

	2005	2010	2015	2020
	Consumption (million bbl/ day)			
Industrialized Countries				
North America	25.6	27.6	29.9	32.2
United States	21.2	22.7	24.3	25.8
Canada	2.1	2.1	2.2	2.2
Mexico	2.3	2.8	3.4	4.2
Western Europe	14.7	15.1	15.3	15.4
United Kingdom	2	2.1	2.2	2.2
France	2.1	2.2	2.2	2.2
Germany	3	3.1	3.1	3.1
Italy	2.1	2.2	2.2	2.2
Netherlands	0.9	0.9	0.9	0.9
Other Western Europe	4.6	4.6	4.7	4.8
Industrialized Asia	7.1	7.3	7.6	7.7
Japan	5.7	5.8	5.9	5.9
Australasia	1.4	1.5	1.7	1.8
Total Industrialized	47.4	50	52.8	55.3
EE/FSU				
Former Soviet Union	4.9	5.6	6.9	7.8
Eastern Europe	1.6	1.6	1.7	1.7
Total EE/FSU	6.5	7.2	8.6	9.5
Developing Countries				
Developing Asia	16.7	20.5	25	29.7
China	5.3	6.7	8.5	10.4
India	2.6	3.4	4.5	5.8
South Korea	2.5	2.8	3.1	3.3
Other Asia	6.3	7.6	8.9	10.2
Middle East	5.6	6.8	8.2	10.3
Turkey	0.8	1	1.1	1.3
Other Middle East	4.8	5.8	7.1	9
Africa	3.4	4	4.6	5.4
C and S America	5.3	6.4	7.7	9.3
Brazil	2.3	2.9	3.6	4.5
Others	3	3.5	4.1	4.8
Total Developing	31	37.7	45.5	54.7
Total World	84.9	94.9	106.9	119.5

Annexure 2.4

Oil trade movements oil trade movements from 1995-
2000 in thousand barrels daily

	1995	1996	1997	1998	1999	2000
Imports						
USA	8831	9400	9907	10382	10550	11092
Western Europe	9567	9539	9413	9971	9731	10066
Japan	5581	5685	5735	5259	5346	5329
Rest of World	12797	13994	15043	14776	15421	16178
Total World	36776	38618	40098	40388	41048	42666
Exports						
USA	949	978	976	1011	956	890
Canada	1402	1484	1492	1603	1520	1703
Mexico	1422	1656	1767	1770	1739	1814
South & Central America	2797	3011	3219	3240	3145	3079
FSU	2731	3239	3413	3569	4019	4273
Central Europe	117	92	142	121	150	121
Middle East	16651	17170	18184	18702	18341	18944
North Africa	2696	2756	2743	2712	2726	2732
West Africa	2723	2916	3102	3094	2985	3293
Asia Pacific*	2576	2790	2735	2490	2650	2848
Rest of World	2712	2526	2325	2076	2817	2969
Total World	36776	38618	40098	40388	41048	42666

Source. BP Amoco Alive, 2001

Annexure 4.1

Major crude oils from Middle East Gulf

Region	Crude	API	Sulphur (wt%)
The Middle East Six			
Iran	Iranian Light	32.56	1.50
	Iranian heavy	30.68	1.92
	Lavan Blend	33.71	1.83
	Sirri	30.9	2.3
	Foroozan	31.3	2.5
Iraq	Basra Light	32.56	2.18
	Kirkuk Blend	35.1	1.97
Kuwait	Kuwait	30.40	2.59
Qatar	Al Rayyan	24.51	3.26
	Al Shaheen	29.02	2.20
	Qatar Manne	35.3	1.57
Saudi Arabia	Arab Light	33.23	1.90
	Arab Medium	31.43	2.47
	Arab Heavy	27.85	2.81
UAE/Dubai	Dubai Export	31.14	1.94
UAE/Sharjah	Mubarek	46.15	0.28
UAE/Abu Dhabi	Asab	40.54	0.81
	Bu Hasa	39.09	0.77
	Murban	39.29	0.80
	Umm Sharif	37.4	1.51
	Upper Zakum	33.23	1.89
Other countries in the Gulf region			
Oman	Oman	33.80	1.14
Sudan	Nile Blend	34.87	0.04
Syna	Synan Light	36.25	0.74
Yemen	Manb Light	49.68	0.07
	Masila	31.05	0.54
Turkey	Turkish Indigenous	32.65	0.73

Source: BP Crude Assay Library reported by Haverly Systems

Annexure 4.2

Major Crude oils from African countries

Region	Crude	API	Sulphur (wt%)	Pour point °C
Nigeria	Bonny Light	37	0.1	-15
	Bonny Medium	25	0.2	-25
	Brass River	41	0.1	0
	Escravos	36	0.1	-12
	Forcados Blend	29.70	0.29	-20
	Odudu	30.86	0.17	-
	Pennington Light	36.60	0.07	6
	Qua Iboe	36	0.1	5
Libya	Amna	36.1	0.15	24
	Boun	25.55	1.85	-
	Brega	40.4	0.21	-1
	Es Sahara	43.19	0.06	-
	Es Sider	36.7	0.37	7
	Sanr	38.3	0.18	-4
	Bu Attifel	44	0.03	30
	Zuetina	41	0.3	10
Algeria	Sirtica	43	0.4	-5
	Saharan Blend	44	0.1	-30
Angola	Zarzaitine Blend	43	0.1	-10
	Cabinda	32.00	0.2	20
Cameroon	Kiame	29.30	0.83	-
	Nemba	38.78	0.17	-
	Palanca	37.15	0.18	-
	Soyo Blend	34.00	0.2	20
	Kole manne blend	35.00	0.3	-6
Congo	Djeno Blend	27	0.3	5
	N'Kossa	48.30	0.06	-
	Yombo	17.70	0.25	-
Zaire (former)	Zaire	30.7	0.16	25
Egypt	Seuz Blend	32	1.5	0
	Belayim	27	2.2	5
	Zaafarana	23.06	3.15	-
Gabon	Mandji	30.5	1.1	3
	Gamba	31.8	0.11	23
	LucinaMarne	39.5	0.05	15
	Ogwendjo	36	0.71	18
	M'Bya	35	0.07	18
	Rabi	34	0.06	18
Tunisia	Ashtart	29	1.0	10
	Didon	34.00	0.82	-
	Rhemoura	31.24	0.89	-
	Tazerka	31.33	0.94	-

Source: Reports of Environmental Technology Center, BP Crude Assay Library reported by Haverly Systems and www.mbendi.co.za

Annexure 4.3

North sea crudes

Region	Crude	API	Sulphur (wt%)
United Kingdom	Brent	38.00	0.44
	Forties Blend	40.96	0.29
	Flotta Mix	36.85	0.82
	Fulmar 568C	41.48	0.24
	Maureen	35.90	0.33
Norway	Ekofisk	38.88	0.83
	Statfjord Snorre	37.76	0.30
	Oseberg	35.86	0.32
	Gullfaks	35.17	0.28

Source. BP Crude Assay Library reported by Haverly Systems

Annexure 4.4

Major crudes from USA and Canada

Region	Crude	API	Sulphur (wt%)
USA	Alaska North Slope	29.57	1.08
	Bay Marchand	35.86	0.25
	Grand Isle	33.23	0.36
	High Island	37.46	0.27
	Light Louisiana Sweet	37.96	0.34
	Ostrea	32.84	0.28
	South Louisiana	32.84	0.30
	WTI	39.29	0.44
Canada	Bow River	24.85	2.48
	Cold Lake	22.98	3.19
	Fosterton	23.82	2.93
	Lloydminster Blend	22.47	2.96
Mexico	Isthmus	32.37	1.35
	Mars	28.39	2.15
	Maya	21.56	3.34
Venezuela	BCF - 17	16.20	2.31
	Bolivar Coast 24	23.40	1.85
	Maralago	20.90	3.38
	Mesa 30	29.48	1.03
	Santa Barbara	33.71	0.64
	Tia Juana	34.48	1.11
Brazil	Marlim	20.24	0.75
Colombia	Cano Limon	29.02	0.52
	Cupiagua	43.08	0.08
	Cusiana	39.39	0.17
Argentina	Neuquen Rio Negro	35.27	0.47
	San Sebastian	69.10	0.01
	Tierra Del Fuego	43.20	0.08

Source. BP Crude Assay Library reported by Haverly Systems

Annexure 4.5

Major crude oils from Russia

Region	Crude	API	Sulphur (wt%)
Russia	Barents Sea	46.71	0.02
	E4 (Gravenshon)	19.84	1.95
	E4 Heavy	18.00	2.35
	Kalingrad	40.96	0.12
	M100 (Atres ex Russia)	17.60	2.02
	M100 Heavy	16.67	2.09
	M100 Res	14.80	2.79
	Onako Light	48.40	0.15
	Onako Medium	38.51	1.15
	Romashkino	31.14	1.30
	Sibenian Light	35.15	0.57
	Urals Light	32.18	1.50
	Urals Heavy	28.39	2.36
	Urals South	33.61	0.92
Kazakhstan	Kumkol	41.20	0.11
	Tengiz	46.60	0.55

Source BP Crude Assay Library reported by Haverly Systems

Annexure 4.6

Major crude oils from Asian countries

Region	Crude	API	Sulphur (wt%)
Indonesia	Arun Condensate	58.18	0.00
	Ardjuna	35.2	0.11
	Attaka	43.52	0.06
	Bekapai	41.20	0.08
	Badak	41.31	0.05
	Bima	21.10	0.25
	Bontang	50.85	0.03
	Cinta	33.40	0.08
	Duri	20.90	0.21
	Kakap	51.50	0.05
	Kerapu	45.15	0.02
	Lalang	38.06	0.05
	LSW Ex Pulau Sambu	30.31	0.13
	LSWR Ex Dumai	27.22	0.13
	Minas	34.46	0.08
	Mudi	36.50	0.44
	Pagerungan	61.28	0.00
	Condensate		
	Sembilang	35.96	0.05
	Udang	37.76	0.04
	Widun	33.30	0.07
	Walio	36.25	0.57
Malaysia	Bintulu	35.96	0.06
	Bunga Kekwa	36.85	0.05
	Dulang	38.47	0.05
	Labuan	31.61	0.08
	Min Light	32.37	0.08
	Tapis Blend	45.27	0.03
	Terengganu	47.39	0.03
Australia	Airlie Blend	43.73	0.02
	Cossack	46.82	0.04
	Jackson	45.38	0.03
	Saladin	48.41	0.02
	Skua	41.48	0.04
	Stag	18.39	0.11
	Surat	44.82	0.03
	Thvenard	37.56	0.04
	Wandoo	19.27	0.14
	Wandoo	19.27	0.14
China	Liu Hua	22.82	0.19
	Lufeng	32.75	0.07
	Nanghai Export Blend	38.78	0.06
Vietnam	Xi Xiang	32.18	0.09
	Bach Ho	40.22	0.04
	Dai Hung	29.11	0.10
	Rang Dong	39.91	0.04
	Ruby	35.66	0.08

Source BP Crude Assay Library reported by Haverly Systems, reports of HPI Consultants, Inc.

Annexure 4.7

Broadly, crude oils can be classified into the following categories on the basis of API gravity and Sulphur content.

Table 1 Crude oil classification

Crude	API	Sulphur	Example Crude (Country of origin)
Heavy High Sulphur (Heavy sour)	< 30	> 1%	Arab Heavy (Saudi Arabia), Al Shaheen (Qatar), ANS (USA).
Heavy Medium-Sulphur (Heavy Medium)	< 30	Bet 0.5% to 1%	Marlim (Brazil), Cano Limon (Colombia), Kiame (Angola).
Heavy Low Sulphur (Heavy Sweet)	< 30	< 0.5%	Bonny Medium (Nigeria), Forcados Blend (Nigeria), Djeno (Congo).
Light High Sulphur (Light Sour)	>= 30	> 1%	Seuz Blend (Egypt), Iranian Light (Iran), Kuwait (Kuwait).
Light Medium Sulphur (Light Medium)	>= 30	Bet 0.5% to 1%	Flotta Mix (UK), Asab (UAE), Synan Light (Syria).
Light Low Sulphur (Light Sweet)	>= 30	< 0.5%	Bonny Light (Nigeria), Brass River (Nigeria), Attaka (Indonesia).

Source. Wang, Haijiang Henry, 1999. China's Oil Industry and Market, Amsterdam. Elsevier, Haverly Library of Crude oils

Annexure 4.8

Table 2 Sweet crude movement (MMTPA)

From/To	Total America	S&C America	Total Europe	Africa	Australasia	Total Asia- Pacific	ROW	Total
Canada		0.2		-	-		-	84.2
Mexico		8.4		0.2	-		0.2	90.4
South & Central America		-		0.6	0.2		-	151.8
Former Soviet Union		8.1		0.5	-		2.3	210.6
Middle East		21.3		34.9	10.1		2.5	941.6
Total Sour	420.6	38.0	379.9	36.2	10.3	568.6	5.0	1478.6
% of total	67.8	69.0	67.7	71.3	35.6	74.7	34.0	70.0
Western Europe	72.2	1.4	9.5	8.4	0.1	9.8	2.3	103.7
Central Europe		-	3.2	-	-	0.1	2.5	5.8
North Africa	17.4	1.3	104.6	3.5	-	5.0	3.2	135.0
West Africa	70.8	6.3	27.7	2.2	-	57.3	-	164.3
East & Southern Africa		-	0.2	-	-	6.1	-	6.3
Australasia	2.4	-	-	-	-	19.8	-	22.2
Japan	0.6	-	0.1	-	0.4	2.8	-	3.9
Other Asia Pacific	9.0	0.1	1.3	-	15.0	70.0	0.8	96.2
China	2.2	0.2	0.1	0.2	0.4	14.1	0.1	17.3
USA	17.7	7.8	10.1	0.3	0.4	5.7	0.8	42.8
Unidentified*	7.3	-	24.8	-	2.3	1.4	-	35.8
Total Sweet	199.6	17.1	181.6	14.6	18.6	192.1	9.7	633.3
% of total	32.2	31.0	32.3	28.7	64.4	25.3	66.0	30.0

Source: BP Amoco Alive, 2001

The total sweet crude traded in the world was 633.3 MMTPA in 2000, accounting for about 30% of the total crude oil movement. The rest is the sour crude, of which Middle East alone accounts for 64%.

The sweet crude trade is fairly distributed among major exporting regions with Africa accounting for 48% of the total exports. Asia – Pacific comes next with 22% followed by Europe with 17%.

Asia-Pacific and North America are the leading importers of the sweet crude, accounting for 32% each of the total sweet crude imports. Europe is the next with 29%.

Annexure 5.1

Crude-wise throughput by Indian refineries (2000-01)

	HPC	BPC	GUJ	RPL	KRL	CPCL	VIS	MRPL	CBU	MAT	PANI	BAR	HAL	GAU	DIG	BRPL	NRL
Indigenous Crude																	
Bombay High	2165	5919	832		3180	1261			9	1555	90						
S Gujarat			2301														
N Gujarat			3371														
Nanmanam									434								
KG Onshore									43								
PY-3						182			39								
Assam-Oil												402		397	679	856	1431
Assam-ONGC												300		310		552	20
Sub-Total	2165	5919	6504	0	3180	1443	0	0	525	1555	90	702	0	707	679	1408	1451
PSC/JVC						0	2577										
Sub total-Indigenous	2165	5919	6504	0	3180	1443	2577	0	525	1555	90	702	0	707	679	1408	1451
Imported																	
High Sulphur																	
Arab Mix (80/20)	2996	15	287		37	1958				275	175		1286				
Basra Light			118			491	60			132	121		523				
Dubai	16	592	164				363	398		55	104		39				
Iran Mix		152	150		1646	84		2382		167	123						
Kuwait		1578	1255		575		777			1443	1474		30				
Murban			12		118			85		32							
Oman																	
Suezmix		51	314		87		130			253	228						
UmmSaif						51											
Upper Zakum	80		543			434	6			809	584		1413				
Zeit Bay					86												
Arab Extra Light	318				123			83									
Qatar Land						52											
Lower Zakum		68															
Masila					31		144	259									
Others				25716	46	41		681									
Sub-Total	3410	2456	2843	25716	2749	3111	1480	3888	0	3166	2809	0	3291	0	0	0	0
Low Sulphur																	
Es Sider			53							44	21						
Badin										45							
Bonny Light			832		819	118	966	134	0	762	890	598	169			82	
Brent Blend			56		40	276	472				26	693	101				
Escravos		163	1284		614	328	558	45		1162	1543	206					
Forcados			402				119			363	317	52					
Labuan						73		260	5			610	236				
Minlight		55				555		5	20				29				
Palanca						2	10					15					
Qua Iboe			31		47	140	72	127		37	12	162	19				
Soyo Blend																	
Others					27		29	1802	8			2					
Tapis								114	21			82	30				
Cabinda					44		58										
Nemba		71					60	63									
Others							6										
Sub-Total	0	289	2658	0	1591	1492	2350	2550	54	2413	2809	2420	584	0	0	82	0
Sub-Total (Imported)	3410	2745	5501	25716	4340	4603	3830	6438	54	5579	5618	2420	3875	0	0	82	0
Total (Ind+Imp)	5575	8664	12005	25716	7520	6046	6407	6438	579	7134	5708	3122	3875	707	679	1490	1451

Source: OCC

Annexure 5.2

Sulphur content of petroleum products under Xth Plan

Motor Spirit

- MS produced in the country meets the sulphur content specification which has been reduced from 0.2% to 0.1% from 2000.
- In accordance with MOST Gazette notification, Euro II vehicular emission norms are in place in the National Capital Region (NCR) and Mumbai and Kolkata municipal area. MS with maximum sulphur content of 0.05% is supplied to these regions.
- MS with sulphur content of 0.05% is to be produced in the rest of the country in 4-5 years.
- Introduction of Euro III emission norms would require MS with a sulphur content of 0.015% to be supplied to the major cities in the next 4-5 years.

High Speed Diesel

In accordance with HSD specifications notified by MOE&F and MOST, the following milestones were achieved or are targeted to be achieved in the country:

- Supply of HSD with 0.5% sulphur (brought down from the earlier level of 0.1%) in the 4 metro cities and Taj trapezium with effect from April, 1996.
- Supply of HSD with 0.25% sulphur in the Taj trapezium with effect from September, 1996.
- Supply of HSD with 0.25% sulphur in inner Delhi with effect from August, 1997.
- Supply of HSD with 0.25% sulphur in entire Delhi, Mumbai, Kolkata and Chennai with effect from April, 1998.
- Supply of HSD with 0.25% sulphur in the entire country with effect from January, 2000.
- In accordance with Bharat stage II vehicular emission norms, HSD with ultra low sulphur content of 0.05% was introduced in NCR in April 2000 for non-commercial vehicles.
- From March, 2001, the entire HSD supplied to the National capital Territory is having sulphur content of 0.05%.
- HSD with sulphur content of 0.05% is being supplied to the Mumbai municipal limit since October 2000 and in the Kolkata municipal limit since January, 2001.
- Plan exists to supply HSD with 0.05% sulphur content in other metros and rest of the country by 2005.

Source. Xth Plan

Annexure 6.1

Charter hire rates for coastal movement of crude

Calculation of Tanker charges (Distance in miles)

From/To	Cochin	Chennai	Haldia	Bombay	Kandla	Vizag	Vadinar
Cochin	0	1752	3060	1170	1906	2280	
Chennai	1752	0	1550	2916	3648	656	
Haldia	3060	1550	0	4224	4956	884	
Bombay	1170	2916	4224	0	830	3444	748
Vizag	2280	656	884	3444	4176	0	
Vadinar				748			0

Speed	12	knots/hr.
	288	knots/day
	331.4246	Miles/day

Charter hire rates	\$/Day	Rs/Day
LR II	15000	690000
LRI	14800	680800
MR	12500	575000

Freight rates LR II (Rs./MT)

From/To	Cochin	Chennai	Haldia	Bombay	Kandla	Vizag	Vadinar
Cochin	0.00	30.40	53.09	20.30	33.07	39.56	0.00
Chennai	30.40	0.00	26.89	50.59	63.29	11.38	0.00
Haldia	53.09	26.89	0.00	73.28	85.98	15.34	0.00
Bombay	20.30	50.59	73.28	0.00	14.40	59.75	12.98
Vizag	39.56	11.38	15.34	59.75	72.45	0.00	0.00
Vadinar	0.00	0.00	0.00	12.98	0.00	0.00	0.00

Freight rates LR I (Rs./MT)

From/To	Cochin	Chennai	Haldia	Bombay	Kandla	Vizag	Vadinar
Cochin	0.00	57.58	100.57	38.45	62.64	74.94	0.00
Chennai	57.58	0.00	50.94	95.84	119.90	21.56	0.00
Haldia	100.57	50.94	0.00	138.83	162.89	29.05	0.00
Bombay	38.45	95.84	138.83	0.00	27.28	113.19	24.58
Vizag	74.94	21.56	29.05	113.19	137.25	0.00	0.00
Vadinar	0.00	0.00	0.00	24.58	0.00	0.00	0.00

Freight rates MR (Rs./MT)

From/To	Cochin	Chennai	Haldia	Bombay	Kandla	Vizag	Vadinar
Cochin	0.00	86.85	151.68	58.00	94.48	113.02	0.00
Chennai	86.85	0.00	76.83	144.54	180.83	32.52	0.00
Haldia	151.68	76.83	0.00	209.38	245.67	43.82	0.00
Bombay	58.00	144.54	209.38	0.00	41.14	170.72	37.08
Vizag	113.02	32.52	43.82	170.72	207.00	0.00	0.00
Vadinar	0.00	0.00	0.00	37.08	0.00	0.00	0.00

Annexure 8.1

ONGC's investment commitments in comparison to exploration investment commitments of other oil majors

ONGC's investment commitments*			
ONGC's investment commitments for IOR and EOR schemes	Rs. Million	47950.1	
incremental oil production in next 20 years	MMT	61.53	
Investment commitment	\$/bbl	2.31	

Exploration commitments of world oil majors in Asia-Pacific region for 2000-01#			
	Exploration (\$ million)	Extensions and discoveries (Million barrels)	Investment (\$/bbl)
Exxon Mobil Corporation	145.0	39	3.7
TotalFinaElf	31.4	1	31.4
Unocal Corporation	134.0	30	4.5
Apache Corporation	40.9	6.1	6.7
Benton Oil and Gas Company	4.3	12.6	0.3
Broken Hill Propriety Company Ltd.	21.9	19.9	1.1
CNOOC Limited	73.7	76	1.0
Fletcher Challenge Energy	11.6	6	1.9
Gulf Canada Resources Limited	27.6	1	27.6
Magellan Petroleum Company	2.0		
New field Exploration Company	9.1		
Nexen Inc.	12.8		
Noble Affiliates, Inc.			
PetroChina Company Limited	1311.4	297	4.4
Pogo Producing Company	11.0	5.6	2.0
Repsol YPF, S.A.	13.8	7.6	1.8
Sinopec Corp.	392.4	133	3.0
Swift Energy Company	1.6	11.2	0.1
Talisman Energy Inc.	20.3	4.1	5.0
Tipperary Corporation	0.4		
Total	2265.1	650	3.5

* ONGC's Annual Report 2000-01

Global E & P Trends 2001, Andersen

Annexure 9.3

Evaluation of options for IOC Koyali

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos - fob (Jan '02)	\$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	\$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Moonng	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost including duty	Rs/MT				8114.72	8114.72
Inland freight (vadinar-refinery)	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	\$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	\$/bbl		0.2	0.2	0.2	0.2
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		2.15	2.94	7.66	6.68
Corporate Tax (at 35%)	\$/bbl		0.75	1.03	2.68	2.34
ONGC net surplus	\$/bbl		1.40	1.91	4.98	4.34

Annexure 9.4

Evaluation of options for IOC Mathura

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light-Escravos - fob (Jan '02)	\$/bbl		19.60	19.60	19.60	19.60
Bonny Light-Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	\$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Mooning	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost including duty	Rs/MT				8114.72	8114.72
Inland freight (vadinar-refinery)	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	\$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	\$/bbl		0.207	0.207	0.207	0.207
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		2.16	2.94	7.66	6.69
Corporate Tax (at 35%)	\$/bbl		0.76	1.03	2.68	2.34
ONGC net surplus	\$/bbl		1.40	1.91	4.98	4.35

Annexure 9.5

Evaluation of option for IOC panipat

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light: Escravos - fob (Jan '02)	\$/bbl		19.60	19.60	19.60	19.60
Bonny Light: Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	\$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost including duty	Rs/MT				8114.72	8114.72
Inland freight (vadinar-refinery)	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	\$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	\$/bbl		0.22	0.22	0.22	0.22
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		2.17	2.96	7.68	6.70
Corporate Tax (at 35%)	\$/bbl		0.76	1.03	2.69	2.35
ONGC net surplus	\$/bbl		1.41	1.92	4.99	4.36

Annexure 9.6

Evaluation of options for Kochi refinery

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos - fob (Jan '02)	\$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	\$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Mooning	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost including duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	\$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	\$/bbl		0.893	0.893	0.893	0.893
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		2.84	3.63	8.35	7.38
Corporate Tax (at 35%)	\$/bbl		1.00	1.27	2.92	2.58
ONGC net surplus	\$/bbl		1.85	2.36	5.43	4.80

Annexure 9.7

Evaluation of options for HPCL Vizag

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos – fob (Jan '02)	\$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos – fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	\$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost including duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	\$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	\$/bbl		0.933	0.933	0.933	0.933
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		2.88	3.67	8.39	7.42
Corporate Tax (at 35%)	\$/bbl		1.01	1.28	2.94	2.60
ONGC net surplus	\$/bbl		1.88	2.38	5.45	4.82

Annexure 9.8

Evaluation of options for MRPL

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light Escravos - fob (Jan '02)	\$/bbl		19.60	19.60	19.60	19.60
Bonny Light Escravos - fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	\$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost including duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	\$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	\$/bbl		0.912	0.912	0.912	0.912
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		2.86	3.65	8.37	7.40
Corporate Tax (at 35%)	\$/bbl		1.00	1.28	2.93	2.59
ONGC net surplus	\$/bbl		1.86	2.37	5.44	4.81

Annexure 9.9

Evaluation of options for CPCL Chennai

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light:Escravos – fob (Jan '02)	\$/bbl		19.60	19.60	19.60	19.60
Bonny Light:Escravos – fob (Jan '02)	Rs/MT	46	6607.04	6607.04	6607.04	6607.04
Freight VLCC	\$/MT				15.27	15.27
Freight VLCC	Rs/MT				702.29	702.29
Fob + freight	Rs/MT				7309.33	7309.33
Insurance	Rs/MT	0.347%			25.36	25.36
Ocean Loss	Rs/MT	0.2%			14.62	14.62
Cif	Rs/MT				7349.31	7349.31
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Mooning	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7433.56	7433.56
LC Charges	Rs/MT	0.3%			22.05	22.05
Basic Customs duty	Rs/MT	10%			743.36	743.36
Cost including duty	Rs/MT				8114.72	8114.72
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6607.04	6607.04	8198.96	8198.96
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.28			327.96
Total payment by ONGC	Rs/MT		2914	2650	2650	2978
ONGC realisation	Rs/MT		3692.76	3957.04	5548.96	5221.00
ONGC realisation	\$/bbl		10.95	11.74	16.46	15.48
Premium (+)/discount (-)	\$/bbl		0.933	0.933	0.933	0.933
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		2.88	3.67	8.39	7.42
Corporate Tax (at 35%)	\$/bbl		1.01	1.28	2.94	2.60
ONGC net surplus	\$/bbl		1.88	2.38	5.45	4.82

Annexure 9.10

Disruption in crude supplies

Date of disruption	Duration in months	Average gross size of shortfall (mb/d)	Reason
11/56 - 3/57	4	2	Suez War
12/66 - 3/67	3	0.7	Synan transit fee dispute
6/67 - 8/67	2	2	Six day war
5/70 - 1/71	9	1.3	Libyan price controversy
4/71 - 8/71	5	0.6	Algerian nationalisation
3/73 - 5/73	2	0.5	Unrest in Lebanon, damage in transit facilities
10/73 - 3/74	6	2.6	Arab-Israeli war
4/76 - 5/76	2	0.3	Civil war in Lebanon
May-77	1	0.7	Damage to Saudi Arab field
11/78 - 4/79	6	3.5	Iranian revolution
10/80 - 12/80	3	3.3	Iran-Iraq war
8/90 - 10/90	3	4.6	Gulf war
Overall Average	3.83	1.84	
Average (1978/79-90)	4	3.8	

Source. Energy Information Administration (USA)

Annexure 9.11

Increase in fixed cost for the refineries

	Unit	HPC	BPC	GUJ	RPL	KRL	CPCL	VIS	MRPL	CBU	MR
Total throughput	'000 tonnes	5575	8664	12005	25716	7520	6046	6407	6438	579	7134
Imported	'000 tonnes	3410	2745	5501	25716	4340	4603	2350	6438	54	5579
Share of ONGC crudes	'000 tonnes	2165	5919	832	0	3180	1261	0	0	9	1555
Replacement imported	'000 tonnes	2165	5919	832	0	3180	1261	0	0	9	1555
Share in total imported	%	6	10	7	29	9	7	3	7	0	8
Disruption	'000 tonnes	139	216	158	641	187	146	59	160	2	178
Old throughput	'000 tonnes	5575	8664	12005	25716	7520	6046	6407	6438	579	7134
New Throughput	'000 tonnes	5436	8448	11847	25075	7333	5900	6348	6278	577	6956
Old Fixed costs	Rs/MT	127	229	182	106	403	382	95	382	37	144
Old Fixed costs	Rs Million	708	1980	2185	2714	3033	2310	609	2459	21	1060
New Fixed costs	Rs/MT	130	234	184	108	414	392	96	392	37	151
Increase in fixed costs	Rs/MT	3	6	2	3	10	9	1	10	0	4
Increase in fixed costs	\$/bbl	0.010	0.017	0.007	0.008	0.031	0.028	0.003	0.029	0.000	0.011

Annexure 9.12

Demurrage Expenses

West Coast India						
Supplier	Quantity (mb)	Load port	Lay Can	Indian coast/port	Freight Rate	Demurrage (\$)
Chevron	1.9	Escravos	6/7 Oct.	WCI	2.675	42500
Chevron	1.9	Escravos	16/17 Oct	WCI	3.275	68000
Vitol	1.84	Escravos	21-Oct	WCI	3.7	68000
Vitol	1.84	Escravos	1/2 Nov	WCI	3.5	60000
Chevron	1.9	Escravos	11/12 Nov	WCI	3.5	60000
Glencore	1.84	Escravos	16/17 Nov	WCI	3.2	48750
Vitol	1.84	Escravos	23/24 Dec	WCI	3.675	55000
Glencore	1.84	Escravos	15/17 Dec	WCI	3.7	52500
Chevron	1.9	Escravos	18/19 Dec	WCI	4.125	68000
Glencore	1.84	Escravos	23/24 Jan	WCI	3.5	55000
Chevron	1.9	Escravos	10/11 Jan	WCI	3.55	50000
NNPC	1.85	Qua lboe + Bonny	15/16 Jan	WCI	4	67500
Glencore	1.84	Escravos	7/8 Feb	WCI	3	48750
Shell	2	Bonny	10/11 Jan	WCI	3.25	59000
NNPC	1.85	Qua lboe + Bonny	15/16 Jan	WCI	3.305	59000
Shell	2	Bonny	22/23 Mar	Vadinar	2.7	52500
Shell	2	Bonny	11/12 Apr	Vadinar	2.5	40000
Vitol	1.84	Escravos	23/24 Apr	Vadinar	2.5	38000
NNPC	1.9	Escravos	16/17 Apr	LPO WCI	2.5	40000
Total demurrage		\$				1032500
Total quantity		million barrels				35.82
Total quantity		million tonnes				4.89
Average demurrage		Rs/T				9.72

East Coast India						
Supplier	Quantity (mb)	Load port	Lay Can	Indian coast/port	Freight Rate	Demurrage (\$)
Shell		2.00 Bonny	6/7 Nov	ECI	4.1	62000
Vitol		1.9 Escravos	24/25 Nov.	ECI	3.7	55000
Vitol		1.9 Escravos	01/2 Dec.	ECI	3.5	48750
NNPC		1.87 Qua lboe+ Bonny	10/11 Nov	ECI	4.215	48750
NNPC		1.9 Qua lboe	10/11 Dec	ECI	3.5	55000
Shell		2 Bonny	16/17 Dec.	ECI	3.5	48750
Vitol		1.9 Escravos	6/7 Jan	ECI	3.475	50000
Shell		2 Bonny	7/8 Jan	ECI	3.825	62500
Glencore	910 kbl	Bonny	10/11 Mar	Sand Heads	1.98	32000
Total demurrage		\$				462750
Total quantity		Million barrels				16.38
Total quantity		Million tonnes				2.23
Average demurrage		Rs/T				9.53

Annexure 9.13

Annutised cost of desalting the BH crude

Head	Unit	Value
Capital Cost	Rs Million	1500.00
Phasing of investment		
Year -2		0
Year -1		0.5
Year -0		0.5
Total		1
Discount factor		0.12
NPV factor		1.12
Capital cost (incl IDC)	Rs.million	1683
Life of plant	Years	15
Capital Recovery Factor		0.15
Annutised capital cost	Rs.million	247
Annutised capital cost	Rs/MT	16.471

Annexure 10.1

Evaluation of options for Koyali refinery

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light - fob (Jan '02)	\$/bbl		19.63	19.63	19.63	19.63
Bonny Light - fob (Jan '02)	Rs/MT	46	6618.84	6618.84	6618.84	6618.84
Freight VLCC	\$/MT				15.43	15.43
Freight VLCC	Rs/MT				709.82	709.82
Fob + freight	Rs/MT				7328.66	7328.66
Insurance	Rs/MT	0.347%			25.43	25.43
Ocean Loss	Rs/MT	0.2%			14.66	14.66
Cif	Rs/MT				7368.75	7368.75
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Moonng	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7452.99	7452.99
LC Charges	Rs/MT	0.3%			22.11	22.11
Basic Customs duty	Rs/MT	10%			745.30	745.30
Cost including duty	Rs/MT				8136.15	8136.15
Inland freight (vadinar-refinery)	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6618.84	6618.84	8220.40	8220.40
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.75			328.82
Total payment by ONGC	Rs/MT		2915	2650	2650	2979
ONGC realisation	Rs/MT		3704.09	3968.84	5570.40	5241.58
ONGC realisation	\$/bbl		10.99	11.77	16.52	15.55
Premium (+)/discount (-)	\$/bbl		-1.112	-1.112	-1.112	-1.112
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		0.87	1.66	6.41	5.43
Corporate Tax (at 35%)	\$/bbl		0.31	0.58	2.24	1.90
ONGC net surplus	\$/bbl		0.57	1.08	4.17	3.53

Annexure 10.2

Calculations for increase in fixed costs

	Unit	NG	SG
Total throughput	000 tonnes	12005	12005
Imported	000 tonnes	5501	5501
Share of ONGC crudes	000 tonnes	3371	2301
Replacement imported	000 tonnes	3371	2301
Total imports	000 tonnes	8872	7802
Share in total imported	%	11.43	10.19
Share in disruption	Million tonnes	0.25	0.22
Old throughput	Million tonnes	12.005	12.005
New Throughput	Million tonnes	11.755	11.782
Old Fixed costs	Rs/MT	182	182
Old Fixed costs	Rs Million	2185	2185
New Fixed costs	Rs/MT	186	185
Increase in fixed costs	Rs/MT	4	3
Increase in fixed costs	\$/bbl	0.011	0.010

Annexure 10.3

Calculation of pipeline costs

Heads	Unit	Value
Length of pipeline from Salaya - Koyali	Km	414
Pipeline cost	Rs million/inch dia/km	0.1
Diameter	Inch	16
Total pipeline cost	Rs million	745.2

Calculation of annutised capital cost

Heads	Unit	Value
Capital Cost	Rs Million	745
Phasing of investment		
Year-2		0
Year-1		0
Year-0		1
Total		1
Discount factor		0.12
NPV factor		1.06
Capital cost (incl IDC)	Rs.million	789
Life of pipeline	Years	30
Capital Recovery Factor		0.12
Annutised capital cost	Rs.million	98
Annutised capital cost	Rs/t	17.17

Annexure 10.4

Calculation of annutised capital cost for the desalter plant

Heads	Unit	Value
Capital Cost	Rs Million	300
Phasing of investment		
Year -2		0.3
Year -1		0.2
Year -0		0.5
Total		1
Discount factor		0.12
NPV factor		1.16
Capital cost (incl IDC)	Rs.million	349
Life of pipeline	Years	15
Capital Recovery Factor		0.15
Annutised capital cost	Rs.million	51
Annutised capital cost	Rs/t	22.30

Annexure 11.1

Evaluation of options for CBU

Element	Unit	Factors	Option A	Option B	Option C	Option D
Arab Light - fob (Jan '02)	\$/bbl		18.81	18.81	18.81	18.81
Arab Light - fob (Jan '02)	Rs/MT	46	6342.36	6342.36	6342.36	6342.36
Freight VLCC	\$/MT				6.38	6.38
Freight VLCC	Rs/MT				293.61	293.61
Fob + freight	Rs/MT				6635.96	6635.96
Insurance	Rs/MT	0.347%			23.03	23.03
Ocean Loss	Rs/MT	0.2%			13.27	13.27
Cif	Rs/MT				6672.26	6672.26
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Mooring	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				6756.50	6756.50
LC Charges	Rs/MT	0.3%			20.02	20.02
Basic Customs duty	Rs/MT	10%			675.65	675.65
Cost including duty	Rs/MT				7367.93	7367.93
Inland freight	Rs/MT		0.00	0.00	0.00	0.00
Price received by ONGC	Rs/MT		6342.36	6342.36	7452.17	7452.17
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	253.69			298.09
Total payment by ONGC	Rs/MT		2904	2650	2650	2948
ONGC realisation	Rs/MT		3438.66	3692.36	4802.17	4504.08
ONGC realisation	\$/bbl		10.20	10.95	14.24	13.36
Premium (+)/discount (-)	\$/bbl		1.083	1.083	1.083	1.083
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		2.28	3.03	6.33	5.44
Corporate Tax (at 35%)	\$/bbl		0.80	1.06	2.21	1.90
ONGC net surplus	\$/bbl		1.48	1.97	4.11	3.54

Annexure 11.2

Calculation for fixed cost

	Unit	CBU
Total throughput	000 tonnes	579
Imported	000 tonnes	54
Share of ONGC crudes	000 tonnes	434
Replacement imported	000 tonnes	434
Total imports	000 tonnes	488
Share in total imported	%	0.65
Share in disruption	Million tonnes	0.014
Old throughput	Million tonnes	0.579
New Throughput	Million tonnes	0.565
Old Fixed costs	Rs/MT	36.58
Old Fixed costs	Rs Million	21.18
New Fixed costs	Rs/MT	37.50
Increase in fixed costs	Rs/MT	0.920
Increase in fixed costs	\$/bbl	0.003

Annexure 12.1

Evaluation of options

Element	Unit	Factors	Option A	Option B	Option C	Option D
Bonny Light – fob (Jan '02)	\$/bbl		19.63	19.63	19.63	19.63
Bonny Light – fob (Jan '02)	Rs/MT	46	6618.84	6618.84	6618.84	6618.84
Freight VLCC	\$/MT				16.60	16.60
Freight VLCC	Rs/MT				763.59	763.59
Fob + freight	Rs/MT				7382.43	7382.43
Insurance	Rs/MT	0.347%			25.62	25.62
Ocean Loss	Rs/MT	0.2%			14.76	14.76
Cif	Rs/MT				7422.82	7422.82
Port dues	Rs/MT	11.04			11.04	11.04
Berth Hire	Rs/MT					
Pilotage	Rs/MT	24.794			24.79	24.79
Garbage charges	Rs/MT	0.01			0.01	0.01
Pier Dues	Rs/MT	18.4			18.40	18.40
Pumping facilities	Rs/MT					
Transshipment	Rs/MT					
Moonng	Rs/MT					
Stream Dues	Rs/MT					
Wharfage	Rs/MT	30			30.00	30.00
Landing charges	Rs/MT				84.24	84.24
CIF + Landing charges	Rs/MT				7507.06	7507.06
LC Charges	Rs/MT	0.3%			22.27	22.27
Basic Customs duty	Rs/MT	10%			750.71	750.71
Cost including duty	Rs/MT				8195.79	8195.79
Inland freight (Haldia-refinery)	Rs/MT					
Price received by ONGC	Rs/MT		6618.84	6618.84	8280.03	8280.03
Cess	Rs/MT		1800	1800	1800	1800
Royalty	Rs/MT		850	850	850	850
Central sales tax	Rs/MT	4%	264.75			331.20
Total payment by ONGC	Rs/MT		2915	2650	2650	2981
ONGC realisation	Rs/MT		3704.09	3968.84	5630.03	5298.83
ONGC realisation	\$/bbl		10.99	11.77	16.70	15.72
Premium (+)/discount (-)	\$/bbl		-0.046	-0.046	-0.046	-0.046
ONGC cost of production	\$/bbl		9	9	9	9
ONGC surplus	\$/bbl		1.94	2.72	7.65	6.67
Corporate Tax (at 35%)	\$/bbl		0.68	0.95	2.68	2.33
ONGC net surplus	\$/bbl		1.26	1.77	4.97	4.33

Annexure 12.2

Increase in fixed costs

	Unit	Barauni	Haldia	GUW	Digboi	BRPL	NRL
Total throughput	Thousand tonnes	3122	3875	707	679	1490	1451
Imported	Thousand tonnes	2420	3875	0	0	82	0
Share of ONGC crudes	Thousand tonnes	300	0	310	0	552	20
Replacement imported	Thousand tonnes	300	0	310	0	552	20
Share in total imported	%	4	5	0	0	1	0
Disruption	Thousand tonnes	79	112	9	0	18	1
Old throughput	Thousand tonnes	3122	3875	707	679	1490	1451
New Throughput	Thousand tonnes	3043	3763	698	679	1472	1450
		3.043	3.763	0.698	0.679	1.472	1.450
Old Fixed costs	Rs/MT	255	281	490	1635	255	255
Old Fixed costs	Rs Million	796	1089	346	1110	380	370
New Fixed costs	Rs/MT	262	289	496	1635	258	255
Increase in fixed costs	Rs/MT	7	8	6	0	3	0
Increase in fixed costs	\$/bbl	0.020	0.025	0.019	0.000	0.009	0.000

Annexures

Part-2

Annexure 13.1 Overview of the Indian gas industry

Oil and gas were discovered in India in 1886 in Upper Assam. The Naharkatyia oilfield in Assam was the first oil and gas discovery of independent India in 1953, followed by the Moran field in 1956. Commercial utilization of natural gas in India started in the early sixties in Assam but really picked up after the development of the giant Bombay high field in the early eighties. Subsequently, South Bassein, another very large gas field was discovered in 1978 in the western offshore basin and brought into production around 1990.

The early focus was on oil production and as a result large amount of associated gas from producing oil fields was flared due to a lack of infrastructure and markets. Free gas finds were shut in for the same reason.

It was only in the early 1980's that the western offshore gas began to be exploited as a resource rather than being treated as a by-product. The government appointed a number of committees and expert groups to examine the ways in which the gas could be best utilised. The view that emerged was that the optimal use of gas would be in producing fertilisers. Initially there was quite some opposition to the use of gas for power generation but later the idea was accepted. In 1986 work began on the Hazira-Bijaipur-Jagdishpur (HBJ) gas transmission line linking the western offshore gas fields with fertiliser and power plants (Map 13.1.1). This resulted in a significant growth in gas production and use through the late 1980's. Flaring from the western offshore has diminished substantially in recent years and is now limited to only technical flaring. While the bulk of the western offshore gas is brought to Hazira, a part of it is taken to Uran in Maharashtra for use by power plants, urea plants and industries around Mumbai.

In the north-east, gas is produced in Assam, Arunachal Pradesh and Tripura. Associated gas has been produced in Assam for over 20 years but flaring has remained at high levels till recently. Free gas fields in Tripura are being used mainly for power generation. Some associated gas is being produced in Arunachal Pradesh but utilisation by a proposed gas-to-liquid plant is yet to start. Consequently, this gas has to be flared.

Next to Gujarat and the north-east, Andhra Pradesh has the largest gas reserves. Gas from ONGC's onshore fields and the offshore Ravva field is being used in producing urea, power generation and in industry. ONGC has made a number of discoveries in the area recently and gas has been allocated by the

government for new power plants with a proposed capacity of 1800 MW. Cairns Energy has recently announced a discovery in an offshore field named Annapurna from where they expect a peak production of around 5 MMCMD. There is an expectation of more gas finds in the area as exploration proceeds in the NELP blocks. Rajasthan and Tamil Nadu also use gas in small quantities.

Gas reserves and production

Gas reserves

The balance recoverable reserves of natural gas increased steadily from 1975 to 1999 but are now declining.

Table 13.1.1 State-wise reserves of natural gas (BCM)

Gas reserves (BCM)	1975	1980	1985	1990	1995	1998	1999 (P)
<i>Onshore</i>							
Gujarat	15.72	16.39	21.87	92.58	89.88	84.24	-
Assam	65.24	63.53*	87.67*	135.47*	159.18*	187.73	-
Rajasthan	0.43	0.43	0.54	1.04	4.11	4.44	-
Total	81.39	80.95	110.08	229.09	253.17	276.41	279
<i>Offshore</i>							
Bombay High	6.28	270.96	368.55*	457.36	406.47**	398.34	369
Grand Total	87.67	351.91	478.63	686.45	659.64	674.75	648

* includes natural gas reserves in Tripura, Nagaland, Tamil Nadu, Arunachal Pradesh & Andhra Pradesh

** includes natural gas reserves in Andhra Pradesh, Gujarat, Tamil Nadu, Andaman and JVC

Source. Indian Petroleum & Natural Gas Statistics - 1997-98 and 1998-99, Ministry of Petroleum & Natural Gas, Govt. of India

According to the Ministry of Petroleum and Natural Gas, the onshore and offshore gas reserves in the country in 1999 and 2000 were as follows.

Table 13.1.2 Gas reserves in 1998/99 (BCM)

Natural gas reserves	1998	1999
Onshore	277	279
Offshore	398	369
Total	675	648

Source. Indian Petroleum & Natural Gas Statistics - 1997-98 and 1998-99, Ministry of Petroleum & Natural Gas, Govt. of India

Unless reserves in existing fields are significantly upgraded or new fields discovered and brought on stream, gas production is set to decline from its current level.

Gas production

Natural gas production in India has grown from 2.4 BCM in 1975/76 to 28.5 BCM in 1999/00.

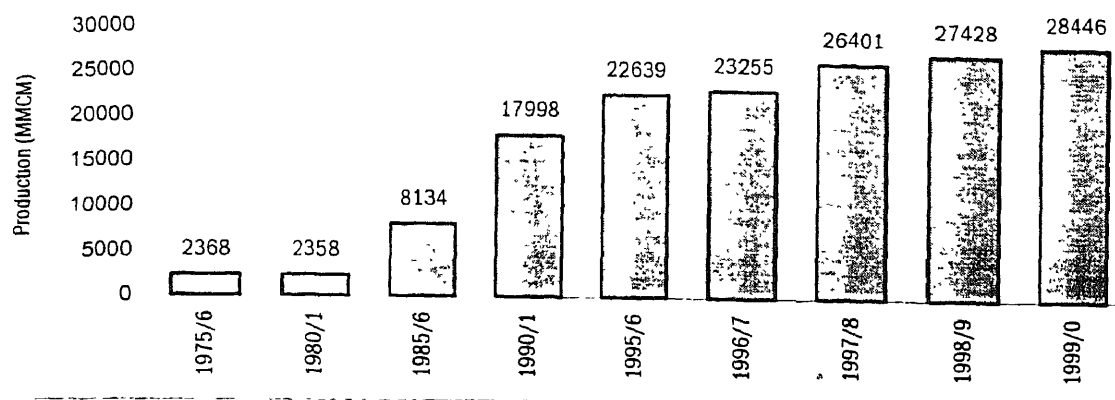


Figure 13.1.1 Gas production in India in million cubic metres

Source. Basic statistics on Indian Petroleum and Natural Gas, 1999-2000, Ministry of Petroleum & Natural Gas, Govt. of India

There are five major areas of gas production in India today:

- The Western Offshore region which extends from offshore Bombay to Gujarat
- North and South Gujarat
- The Krishna Godavari basin in Andhra Pradesh
- The Cauvery basin in Tamil Nadu
- Assam and Arunachal Pradesh

Currently around 75% of India's gas is being produced from the western offshore fields.

Gas supply sector organization

The gas supply sector in India is dominated by public sector enterprises under the administrative control of the Ministry of Petroleum. Ninety percent of the gas is produced by two state owned oil companies, the Oil and Natural Gas Corporation (ONGC) and Oil India Limited (OIL). The balance comes mostly from the medium sized fields - Panna, Mukta and Tapti in the western offshore and Ravva off the Andhra coast - operated by joint ventures of ONGC. Several small gas fields operated in the private sector are also producing gas but their production does not add up to much.

The gas produced by ONGC is marketed by GAIL except gas from isolated marginal fields marketed direct by ONGC. OIL, which operates mainly in Assam and also in Rajasthan sells gas mainly through its own arrangements and partly through GAIL. The gas from Panna-Mukta-Tapti and Ravva is bought by GAIL on behalf of the government. All of this gas is sold only to consumers who are allocated gas by the Government of India. The private operators of small gas fields are free to select their customers. The gas price to be charged by ONGC and OIL and the transportation charges along the HBJ pipeline of GAIL are fixed by the government. Gas from private fields is sold at negotiated prices.

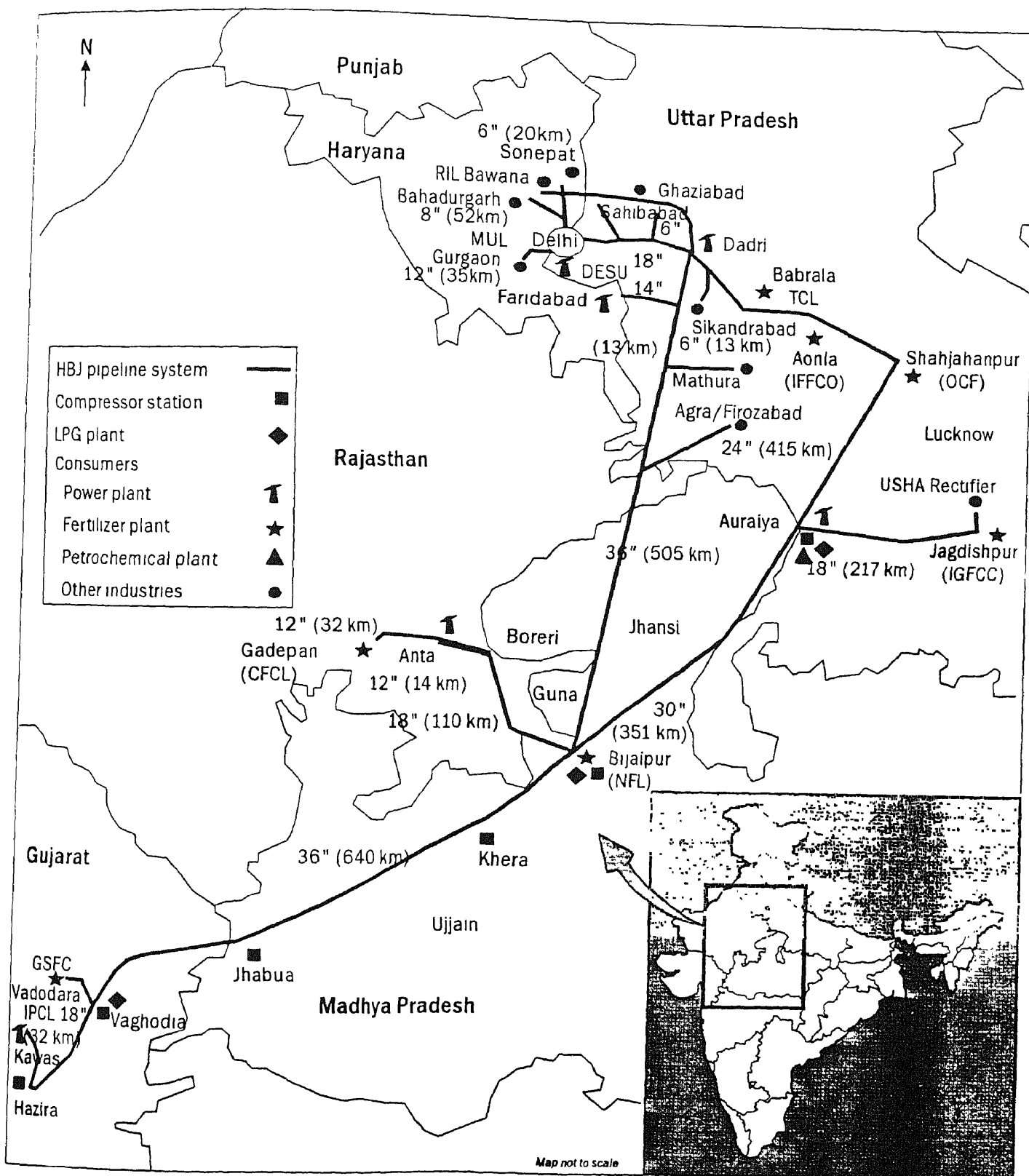
The gas industry infrastructure

The Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline network (Map13.1.1) is the major gas transmission line in India, owned and operated by the Gas Authority of India Limited (GAIL). It starts at Hazira in Gujarat and passes over Rajasthan, Madhya Pradesh, Uttar Pradesh into Haryana. It is 2300 km long with a capacity of 33.4 MMCMD. Spur lines at various points in Gujarat, Rajasthan, Uttar Pradesh, Delhi and Haryana feed power plants, fertiliser plants and industries.

Wet gas from the offshore South Bassein field, off the coast of Maharashtra, is fed by 216 km sub-sea lines of 36" and 42" diameter to ONGC's sweetening and fractional separation plant at Hazira. The gas handling capacity at the Hazira terminal is 41 MMCMD.

With several LNG terminals being planned on the west coast of India, GAIL plans an investment of Rs. 30 billion to expand the HBJ capacity to 60 MMCMD by 2003. GAIL also plans to extend the HBJ pipeline to Ludhiana in Punjab.

Map 13.1.1 The HBJ (Hazira-Bijaipur-Jagdishpur) gas transmission system



In addition to the HBJ pipeline, there are regional gas grids of varying sizes in the states of Gujarat, Andhra Pradesh, Assam, Maharashtra, Rajasthan, Tamil Nadu and Tripura. Most of these regional pipelines (about 725 km) were constructed and operated by ONGC but ownership and operation of these gas grids were passed on to GAIL in the nineties. The present grid capacity is based on the gas availability from the producing areas as well as the outlook for future gas production. In view of the increased availability of gas in the KG basin, GAIL has announced plans for augmenting pipeline capacity in Andhra Pradesh.

Distribution

The Mahanagar Gas Limited, a joint venture between GAIL and British Gas is supplying gas to around 50,000 houses in Mumbai as well as small industrial and commercial units and CNG filling stations. The Indraprastha Gas Limited, a joint venture of GAIL and BPCL is supplying gas in Delhi to around 1000 houses and 80 CNG stations. At the instance of the Supreme Court, the fleet of buses, taxis and rickshaws in Delhi is being converted to CNG. The other cities with natural gas distribution systems are Vadodara, Surat and Ankleshwar in Gujarat and a few towns in Assam and Tripura in the north-east.

Exploration prospects and present activity

Sedimentary basins in India

There are 26 sedimentary basins in India extending over 1.39 million square kilometres onshore, 0.4 million square kilometres offshore and about 1.35 million sq. km in deep waters.

The basins have been categorized according to their prospectivity; Category I consist of producing basins, while Categories II to IV are basins with reducing prospectivity. The Category I basins include:

- Cambay Basin, Gujarat
- Bombay Offshore
- Cauvery Basin
- Krishna-Godavari Basin
- Assam Shelf/Assam Arakan Fold Belt

Exploration during the 1960s and 1970s was concentrated in category I basins. The three main producing basins in the country, the western offshore region, the Cambay basin in Gujarat, and Upper Assam region, are in the mature phase of exploration and with the exception of Assam, future finds in these areas are not

likely to be large in size. The deep water basins now being explored hold some promise of large discoveries.

Although the state owned enterprises increased hydrocarbon production and the reserve base significantly over the period 1975 to 1990, the gap between domestic production and demand widened in the later years. As a result, steps were taken to encourage private sector investment into exploration and production with exploration acreage offered to private companies under production sharing arrangements with the Indian government. Nine rounds of bidding were followed in 1999 by the New Exploration Licensing Policy (NELP) offering a level playing field to private and public sector oil companies. The first round of the NELP was launched in 1999. 25 blocks from this round were awarded last year and these have started showing results with discoveries offshore Gujarat and Andhra Pradesh. Exploration in the other blocks is in progress. With \$250 million committed to be spent by the exploring companies, there is expectation of more oil and gas finds. Subsequently, 23 blocks have been awarded in the second bidding round launched in late 2000.

Alternative sources of gas

Coal bed methane (CBM)

The production of natural gas from coal – coal bed methane (CBM) – has been undertaken in several countries over the last decade, especially in the United States. India holds significant prospects for exploitation of CBM as a new source of energy. There are about 200 billion tonnes of coal reserves predominantly in the eastern part of India – Bihar, West Bengal and Madhya Pradesh. It is estimated that 70 – 75 billion tonnes of coal reserves are beyond 600 metres in depth and thus not extractable with the current mining technologies. These reserves would potentially be available for exploitation of CBM. The existence of gaseous mines is well established in India, notably in Damodar Valley coal fields in Bihar and Bengal. Analysis of the coal in the Damodar Valley has indicated that upto 10 cubic metres of methane gas per tonne of coal may be present at a medium depth of burial.

There are large lignite reserves in Gujarat at the depth of 1,000 – 1,500 metres. GAIL and ONGC have agreed to jointly undertake a project for assessing the CBM potential of coal deposits in north Gujarat.

After taking into account the future coal- mining programme by coal companies, 7 blocks have been offered for exploration and exploitation through global competitive bidding by the government. The prognosticated CBM

resource in these blocks is around 400 BCM as estimated by the Director General of Hydrocarbons (DGH).

Table 13.1.3 Prognosticated CBM resources

Coalfield	Block/State	Area covered (in sq. k.m.)	Prognosticated CBM resource (in Tcf)
<i>Gondwana Coal</i>			
Raniganj	Northern Raniganj (West Bengal)	232.00	1.030
Raniganj	Eastern Raniganj (West Bengal)	500.00	1.850
Jharia	Southern part of Jharia Coalfield (Bihar)	69.20	2.407
Bokaro	Bokaro Basin (Bihar)	93.97	1.590
Birbhum	Birbhum (West Bengal)	250.00	1.000
N. Karanpura	N. Karanpura (Bihar)	340.54	2.181
Sohagpur	Eastern Sohagpur (M.P)	495.00	3.030
Sohagpur	Western Sohagpur (M.P)	500.00	
Satpura	Satpura Basin (M.P)	500.00	1.000
Total		2980.71	14.088 or 398.92 BCM gas in place

Source: Hydrocarbon Vision 2025, GoI

These resources can yield an average production level of 22 MMCMD for a period of 25 years, assuming a recovery factor of 60%. Bids received for the blocks is now under evaluation.

Demand for natural gas

Past trends in gas demand

Although the use of natural gas has increased rapidly, natural gas accounts for only around 11% of the primary energy in use. Till the late 1980s the demand lagged behind the production potential mainly because of lack of infrastructure. However, in the 90's, the demand has exceeded the supply.

In view of the shortage of gas, the government of India allocates gas to all consumers. The power and fertilizer sectors have been allocated most of the gas. These two sectors together consume about 80% of the gas today. The sponge iron units consume another 10%. The balance goes to industrial units where it replaces mostly fuel oil and some LPG. As noted earlier, gas is also supplied to the residential and the commercial sectors in Mumbai, Delhi and a few towns of Gujarat, Assam and Tripura. This gas is used for cooking only, as space heating is not required. The daily requirement of households is only around 1 cum. With such low requirements and the subsidy on domestic LPG, the demand from this sector will continue to be low. The use of CNG in lieu of petrol has been popular in Mumbai and Delhi.

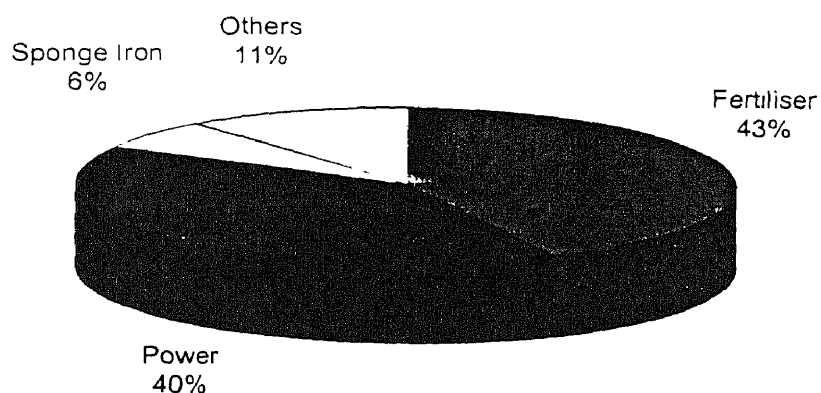


Figure 13.1.2 Sectoral gas sales (1998/99)

Source. GAIL

Area wise and sector wise use of natural gas in 1998/99 was as shown in the Table below:

Table 13.1.4 Gas utilization: 1998/99 (MMCMD)

Area	Fertilizer	Power	Sponge Iron	Others	Total
<i>Western Offshore</i>					
Uran	5.0	4.7	1.4	0.7	11.8
HBJ	13.0	9.1		2.5	24.6
Hazira	2.7		2.0	1.2	5.9
<i>Western Onshore</i>					
Rajasthan	1.2	4.2		1.4	6.8
K. G. Basin		0.4			0.4
K. G. Basin	1.7	2.2		0.1	4.0
Assam	0.0	0.4		0.1	0.6
Tnpura		0.8		0.0	0.8
Cauvery Basin		0.0		0.1	0.1
Total	23.6	21.9	3.5	6.1	55.1

Source. GAIL

Among the states, Gujarat uses more gas than any other state in India.

Gas use in fertilizer industry and power generation

The fertilizer industry is currently the largest single gas consumer in India accounting for about 44% of the total sales. Gas utilization for fertilizer production in India started in earnest in the early 1980s.

The choice of feedstock for fertilizer production has been primarily determined on the basis of availability of feedstock and government policies in place. Immediately following the fertilizer industry, the power sector is the second largest consumer of gas in India.

Other industries

Gas utilization is preferred in industries where heat control and low sulphur are prerequisites in the fuel used such as glass, ceramics, textiles, electronics (picture tubes) etc. It is also used in the sponge iron (or DRI) industry and in the production of methanol.

The sponge iron industry

In the sponge iron industry, natural gas is used as a primary agent for the reduction of iron oxides into metallic iron, either in the form of Hot Briquetted Iron or iron carbide, for subsequent use in the manufacture of steel slabs and billets. DRI is a substitute for the use of scrap as a feedstock in arc and blast furnaces. The Midrex process is used in India by both Essar and Vikram Ispat at Hazira and Raigarh respectively, whilst the HYL III process is used by Grasim, also at Raigarh.

The production of methanol

Natural gas is the dominant feedstock for production of methanol through the partial oxidation process. Methanol is one of the major basic chemical raw materials. At present methanol production in India from gas is limited to a single plant in Gujarat operated by Gujarat Narmada Fertilizer Company.

The glass and ceramics industry

Gas is used in the glass and ceramics industry to fire furnaces in which the raw materials, fluxes and oxidising agents are mixed. The demand from the glass industry is relatively low – a typical glass plant would consume no more than 0.1 MMCMD. The glass industry will be a willing consumer of gas but will not be able to provide an anchor load.

Other areas of gas use

Gas is also used in industries for process heating and steam-raising. Oil refineries use some gas to produce H_2 for de-sulphurisation and hydro-cracking.

The domestic sector

For domestic consumers, the main use of gas will be in replacing kerosene and LPG for cooking. Domestic consumers have to piggyback on large consumers as the city distribution projects would not be viable otherwise.

Expected trends in gas demand

The demand for gas up to 2025, the indigenous supply and the deficit have been examined in the Hydrocarbon Vision 2025 brought out recently by the Government of India. The requirement of gas over this time horizon would depend upon a number of factors and their complex inter-relationship. The growth in energy consumption would depend upon the growth of population and of GDP, the structural changes in GDP, the growth of industrial and agricultural sectors, energy pricing and tariffs and the success of energy conservation measures based on the need to contain damage to the environment.

According to the Vision document, the power and the fertiliser sectors would dominate gas consumption and the demand would build up as shown below.

Table 13.1.5 Total gas demand (MMCMD)

	1998/99	2001/02	2006/07	2011/12	2024/25
<i>Power</i>					
Scenano 1*	22	40	67	90	153
Scenano 2**	22	67	119	168	208
<i>Fertilizer</i>	24	54	66	83	105
<i>Others*</i>					
Scenano 1	9	23	33	43	64
Scenano 2	9	30	46	63	78
<i>Total</i>					
Scenano 1	55	117	166	216	322
Scenano 2	55	151	231	313	391

* gas at \$4/MMBtu

** gas at \$3/MMBtu

other sectors account for 20% of total demand in 2002 and thereafter

Source. Hydrocarbon Vision 2025, GOI

Our own estimates of gas demand are more conservative, as we shall see in the next chapter.

Future gas production projections

ONGC draws up long term profiles of gas production every year. These are based on development plans already finalized as well as in anticipation of future discoveries. Current projections show that the total gas production would decline steadily until the Bombay High gas cap is brought into production. This is expected between the years 2015 and 2020.

Demand - supply balance

The declining production profile coupled with the projection of rising demand shows a widening demand-supply gap. This implies that exploration efforts need to be stepped up and the feasibility of importing gas from the neighbouring countries examined seriously. The initiatives and prospects for exploration have been described earlier. The options for importing gas through pipelines are outlined below.

Pipeline gas import projects

Oman – India deep water pipeline

An in-principle agreement was signed by the governments of India and Oman in September 1994 for the import of 56.6 MMCMD of gas through two sub-sea pipelines. The gas from the first pipeline was to be utilized in western and northern India and the second was planned to be taken to south India. In order to avoid the territorial waters and the Exclusive Economic Zone (EEZ) of Pakistan, a deep-sea route was proposed. Parts of the route lay at water depths exceeding 3000 metres. The Oman Oil Company could not develop the necessary technology to lay pipelines at that depth. Also, the proven gas reserves in Oman did not support both the pipeline and the LNG Projects. As a result, the pipeline proposal has not been seriously pursued after 1997.

Iran – Pakistan – India

India and Iran signed a MoU in 1993 to study the feasibility of importing 50-75 MMCMD of gas through a pipeline landing in Kachchh in India. A shallow offshore route through the EEZ of Pakistan was proposed. A feasibility study was awarded to PLE of Germany. However, work on the feasibility study could not be started as the government of Pakistan did not permit the route survey. An onland alternative through Pakistan has also been under consideration. Pakistan had favoured this option but the Indian side has worried about the security of supplies. Progress on the project will be possible only when the relations between India and Pakistan improve.

Bangladesh - India pipeline

Unocal and Shell have led the efforts being made to import gas from Bangladesh to India. Unocal has proposed pipelines from the Bibiyana fields in Bangladesh whereas Shell has proposed bringing gas from the Sangu fields in offshore Bangladesh. Some of the proposals involve small quantities to be brought to Bengal. Among the larger proposals, Unocal has envisaged bringing 500 mcfcd to

be fed into the HBJ. A consortium of ONGC, IOC and GAIL would market the gas. Bangladesh has so far not agreed to export proposals on the ground that the gas is required for consumption within Bangladesh. However, the Bangladesh government has recently formed a Committee to look into gas utilisation. The future of these proposals will depend on the recommendations of the Committee.

Myanmar – Bangladesh – India

GAIL has an MOU with Cairns Energy / Shell and Halliburton for the study of a 1 bcf/d pipeline from Myanmar via Bangladesh. The proposed pipeline alignment covers Orissa, Andhra Pradesh, the eastern portion of Karnataka and Tamil Nadu. Myanmar is yet to prove sufficient gas reserves to support such a project.

Turkmenistan – Afghanistan – Pakistan – India

This proposal was pursued by Unocal of USA under the Centgas consortium, for bringing gas from Turkmenistan's Dauletabad fields to markets in northern Pakistan, with the potential of an extension from Multan to New Delhi, India. Unocal formally withdrew from the venture in 1998 on account of the situation in Afghanistan. The recent changes in Afghanistan will no doubt re-generate interest in the proposal.

Qatar – India

A proposal for bringing gas by pipeline from Qatar through Pakistan has been promoted by Crescent Company of Sharjah but little progress has been made.

The projects listed above are considered economically viable. The problems are political in nature and an early solution of the problems is unlikely.

Import of LNG

The status of LNG import projects is examined in Annexure 13.5 of this report.

Domestic gas price

The price of gas sold by ONGC through GAIL, the price of gas from fields operated by joint ventures and also transportation charges along the HBJ are fixed by the Government. Gas from private fields are sold at negotiated prices.

The price of natural gas has been fixed by the Government since 1987. In 1987, the price was Rs 1400/mcm for gas at landfall points and a flat Rs 2250/mcm for gas along the HBJ line. The gas price was much lower than the

prices of alternative fuels and the government felt the need to bring the price to the consumer in line with these prices.

The Kelkar committee was appointed in 1990 to recommend revisions in the gas prices. The committee recommended that the price payable to the producers be fixed on the basis of the long run marginal cost of production estimated at Rs 1500/mcm. The consumer price was to be increased annually to reach Rs 1850/mcm, which was near enough to the prevailing fuel oil price. The difference between the consumer price and the producer price was credited to the Gas Pool Account – an account set up to compensate ONGC and OIL for the concessional price of gas in the North-East.

In 1996 the Sankar Committee was established to review the above rates, with some consideration given to the impending need for gas imports and the effects of import parity pricing. The committee decided that import parity pricing would be too steep a transition. The committee left intact the principles of fixing the producer price and the consumer price earlier recommended by Kelkar. The prices were however revised upward based on fresh estimation of the costs.

Having considered these recommendations, in October 1997 the government instituted a new series of gas prices, valid through to March 31, 2000. The consumer price of gas at landfall points were linked to the price of a basket of fuel oils as shown in the table below.

Table 13.1.6 Natural gas pricing against a basket of fuel oils (%)

Year	Percentage of LSHS/FO price	
	General price	Concessional price for the NE states
1997-98	55	35
1998-99	65	40
1999-2000	75	45

The price is determined and notified by GAIL with the approval for the Ministry for every quarter depending upon the average price of the following basket of fuel oils (with equal weights to each type) based on the figures obtained from Platt's Oilgram for the previous quarter.

- Cargoes FOB, Med Basis, Italy (1% Sulphur)
- Cargoes CIF NEW Basis, ARA (1% Sulphur)
- Singapore, FOB, HSFO 180 cst (3.9% Sulphur)
- Arabian Gulf, FOB, HSFO 180 cst (3.9% Sulphur)

The price varies between the floor of Rs 2150/mcm and the ceiling of Rs 2850/mcm. This consumer price of gas is linked to a calorific value of 10000 kcal/m³. The price has now reached the ceiling and is being reviewed with a view to introducing 100% fuel oil parity prices.

ONGC/OIL/GAIL and joint venture operations are permitted to sell gas from marginal isolated fields to be developed in future, at market driven prices.

The transportation charge along the HBJ pipeline was fixed at Rs 1150/mcm and has increased since 1997 by 1% for every 10% increase in the consumer price index. This increase is paid to GAIL out of the Gas Pool Account. The transportation charge has been linked to the calorific value of 8500 Kcal/m³. Out of the consumer prices collected by GAIL, GAIL retains the amount required to pay for the higher cost of gas purchased from the joint venture companies who are paid full fuel oil parity prices.

The above prices are applicable to gas sold by ONGC or OIL to GAIL and to sales by GAIL to consumers. Sales by private field operators are linked to fuel oil prices. The prices applicable at different interfaces are as shown below.

Gas sales by ONGC/OIL to GAIL

As detailed above.

Gas sales by private upstream companies To GAIL

These are negotiated between the government and the private operators and included in the production sharing contracts. So far these prices have been full fuel oil parity prices but the fuel oils basket could differ from one case to another.

Direct to end-users

These are freely negotiated and are mostly linked to prices of alternative fuels. Transportation charges are also negotiated.

Gas sales by GAIL to end-users

As detailed above. The transportation charge on the HBJ pipeline provides GAIL a 12% post-tax return on net worth. The transportation charges on other pipelines is fixed by GAIL on the same principle.

Gas sales by GAIL to distribution companies

The distribution companies pay the same price to GAIL as any other customer.

Gas sales by distribution companies to end-users

These are negotiated prices linked to alternative fuels.

Taxes and duties

In addition to the price as fixed above, royalty, taxes, duties and other statutory levies on the production and sale of natural gas is payable by the consumer. The royalty on gas as fixed under the Oilfields Development Act is 10% of the wellhead price. There is no cess on natural gas (unlike crude oil) although a cess could be levied under the law. There is no excise duty as natural gas or on crude oil as these are minerals although excise duty is charged on petroleum products. A sales tax is leviable at state rates if the sale is within the state or at the central rate of 4% for inter-state sales. The state sales tax rates vary from one state to another, ranging from zero to 22%.

A typical price build up for gas produced in a state and sold within the state would be as below.

	\$ / MMBtu
Gas price	1.80
Royalty	0.18
Transportation charge	0.43
Sales tax (20%)	0.48
Total	2.89

It is to be noted that GAIL does not make a margin on merchant sales; it is allowed a return only on its investment in the pipeline.

In addition to this, there would be a customs duty to be paid on imported gas/LNG. This duty is now 5%. A countervailing duty of 16% was levied till last year on LNG except when used for power generation. This has now been removed so that the duty is now the same for all consumers. The gas industry has been asking for 'infrastructure' status, with a consequent reduction in the customs duty to be paid on components imported for pipelines and LNG receiving terminals. The concession, if granted, could make a difference of around 7-8 cents/mmBtu in the regasification cost. However, there is no guarantee that the benefit would be passed on to the consumer. The government has not yet agreed and is not likely to agree.

Contractual arrangements for sale of gas

There is no contract as yet between ONGC and GAIL regarding gas supplied by the former to the latter. This has not given rise to major problems as both are public sector undertakings. For supplies to its consumers, GAIL has evolved a

standard contract to which case-specific small variations can be made. The major points covered in such contracts are:

- *Period of contract*: The period is between 10 and 15 years from the date of commencement of supply.
- *Activity milestones for new customers*: The contract spells out the dates of completion of major activities for new plants like purchase of land, ordering of equipment, commencement of construction, completion of construction, etc. The contract requires all purchasers to lodge with GAIL a refundable cash deposit and a bank guarantee (equivalent to about three times the cash deposit). GAIL is required to pay interest on the cash deposit. The contract also stipulates that GAIL has the right to forfeit 25% of the bank guarantee for delay in completion of any of the stipulated major activities in a new plant beyond three months of the milestone schedule. The right of GAIL to cancel the contract for further delays in construction activities is also incorporated in the contract.
- *Manner of delivery of gas*: The inlet pressures, location of the Gas Metering Station, its installation and maintenance by the seller at the consumer's cost and provision of a check metering station by the consumer, are provided in the contract. Besides, frequency and method of calibration of metering unit are specified.
- *Quantity of gas*: The progressive schedule of delivery is indicated in the contract in terms of daily quantity. However, prior to each contract year the customer is required to indicate a forecast of gas requirement. The customer guarantees a minimum off-take of around 80% of the contracted quantity and payments being made up to this 80% level even when the off-takes are lower (take or pay).
- *Specification of gas*: The quality of gas to be supplied and the method to be followed for gas sampling is annotated. Typical limits of composition of the gas at the delivery point are indicated.
- *Price of gas*: This is as decided by the GOI in its price notification that is issued periodically. In addition transportation charges, royalty, taxes, duties and other statutory levies of the Central/State Government or any other local bodies are borne by the buyer.
- *Transport cost*: This is either a fixed amount as for delivery ex-HBJ pipeline or according to a formula, where a new gas line is laid for making supplies of gas available to a consumer. In respect of existing customers outside the HBJ pipeline, the transport charges as earlier agreed mutually between the supplier and consumer will continue. However, for future the new formula

will be relevant. This formula covers annual depreciation of pipeline cost, reasonable return on capital cost of the pipeline and its operation and maintenance costs. The transport cost is subject to escalation at 3% per annum.

- *Billing and payment terms:* Invoices are submitted fortnightly and customers are to pay within 3 working days of presentation of an invoice. The customer has to open and maintain an irrevocable Letter of Credit with a bank notified by the seller, covering a value of fifteen days supply of gas at maximum contracted quantity and the monthly transportation charge. If, for any reason, payment is delayed or any disallowance made from the invoice, the seller may present the invoice for the full amount or for the amount not paid, as the case may be, to the bank against the Letter of Credit and draw the amount. For supplies to continue, the customer has to reinstate the full amount of L/C.
- *Arbitration:* This is generally guided by the provisions of Indian Arbitration Act. Besides, other Indian Laws relating to contract, etc. are fully applicable.

GAIL's contracts with consumers have been criticised as being one-sided. While GAIL is protected by take-or-pay provisions, there is no penalty on GAIL for short-supply.

Issues in gas contracts

Some of the important points in respect of these contracts between different parties are listed below. First, different prices prevail at different locations depending on the transportation cost and sales tax, but no distinction is made currently between different categories of consumers in the same location with reference to the opportunity value of gas they use. Secondly, supplies of gas to all categories are non-interruptible, except for those delivered to "fall-back" customers. Currently to avoid under-utilisation of available gas, allocations are made in excess of the availability. This requires rationing of gas and the use of alternative fuels. While dual-fuel arrangements were earlier made only as exceptions, the Government now insists on dual-fuel arrangements for all customers. Thirdly, GAIL today discharges the role of both a transporter and a merchant. In the few cases where ONGC and OIL sell gas direct to consumers, they also provide 'bundled' services.

Annexure 13.2 Estimation of gas demand

Power generation

The demand for electricity for past years can be computed by adding the actual consumption and the shortages, both reported by the Central Electricity Authority (CEA). As shown in the Table below, the demand has grown quite rapidly in the recent years.

Table 13.2.1 Statewise electricity demand 1998/99 to 2000/1 (MU)

	1998/99	1999/00	2000/01	Growth rate %
Delhi	16573	17946	19340	8.0
Haryana	14162	15423	16657	8.5
Himachal Pradesh	2896	3123	3502	10.0
Jammu & Kashmir	5792	7145	7435	13.3
Punjab	24886	26223	28621	7.2
Rajasthan	23802	26210	27792	8.1
Uttar Pradesh	42619	49409	53502	12.0
Chandigarh	1033	1117	1201	7.8
Goa	1700	1966	1846	4.2
Gujarat	41702	45412	48911	8.3
Madhya Pradesh	35369	38602	42163	9.2
Maharashtra	66129	74335	82918	12.0
Dadar & Nagar Haveli	727	793	858	8.6
Daman & Diu	442	488	534	9.9
Andhra Pradesh	42077	47218	51056	10.2
Karnataka	30312	31184	33546	5.2
Kerala	12608	13573	14803	8.4
Tamil Nadu	41440	41274	43390	2.3
Pondicherry	1278	1478	1673	14.4
Bihar	14210	14530	15354	3.9
Orissa	11272	12034	12735	6.3
Sikkim	122	137	171	18.4
West Bengal	19478	20985	22450	7.4
Arunachal Pradesh	182.7	186.1	198.6	4.3
Assam	2894.1	3084.9	3159	4.5
Manipur	486.7	548.3	594.5	10.5
Meghalaya	465.1	512.3	559.7	9.7
Mizoram	247.4	264.9	289.2	8.1
Nagaland	225.4	229.8	244.1	4.1
Tripura	514.6	518.8	556.6	4.0
All India	455771	496092	536220	8.5

It is to be noted that the above figures refer to the demand at the bus bar and therefore include the T&D losses.

The last demand projection made by CEA was published in 2000 as the 16th Electric Power Survey (EPS). The 16th EPS has made annual projections up to

2004-05 and long-term projections for 2006-07, 2011-12, and 2016-17, the terminal years of the 10th, 11th and the 12th five-year plans. The projections are based on the analysis of past trends in electricity consumption in the following sectors:

- Domestic
- Commercial and miscellaneous
- Public lighting
- Public water works
- Irrigation and dewatering
- Industrial (HT above 1 MW, HT below 1 MW and LT)
- Railway traction and
- Bulk supply to non-industrial consumers

CEA holds extensive discussions with the power utilities in each state before making these projections. One major problem that makes such projections difficult is that agricultural supplies are not metered. The other problem is that there are large commercial losses. Both of these factors distort the sectoral consumption figures. In spite of this problem, earlier projections by CEA conform quite closely to the unrestricted demand. The growth in internet connections will lead to a high demand in the domestic sector. According to CEA, the latest projections take this into account. The statewise projections are shown in the Table below.

Table 13.2.2 Projections of energy demand (MU)

State	2001-02	2006-07	2011-12	2016-17
Northern region				
Haryana	17460	25750	37801	55234
Himachal Pradesh	3656	5113	7118	9863
Jammu & Kashmir	6796	9099	12125	16081
Punjab	29824	41922	58661	81700
Rajasthan	28852	40341	56133	77741
Uttar Pradesh	50087	70803	99631	139542
Chandigarh	1337	2120	3347	5259
Delhi	19454	25672	33712	44060
Sub Total	157466	220820	308528	429480
Western region				
Goa	1740	2207	2786	3501
Gujarat	46393	61683	81615	107479
Madhya Pradesh	39167	51952	68578	90096
Maharashtra	79593	106892	142911	190167
D&N Haveli	923	1284	1779	2452
Daman & Diu	585	909	1406	2164
Sub Total	168401	224927	299075	395859
Southern region				

State	2001-02	2006-07	2011-12	2016-17
Andhra Pradesh	50493	68797	93289	125905
Karnataka	32950	44748	60478	81354
Kerala	15378	22998	34231	50718
Tamil Nadu	42341	54872	70769	90838
Pondicherry	1818	2687	3951	5784
Sub Total	142980	194102	262718	354599
Eastern region				
Bihar (excl. DVC)	9303	12256	15814	20308
DVC	9213	11129	13365	15974
Orissa	14002	17997	23376	30220
Sikkim	183	239	312	405
West Bengal (excl. DVC)	20885	27846	37529	50341
Sub Total	53586	69467	90396	117248
North-East region				
Arunachal Pradesh	216	303	423	588
Assam	3669	5294	7604	10870
Manipur	643	1039	1672	2679
Meghalaya	644	955	1410	2071
Mizoram	327	525	838	1331
Nagaland	270	388	555	790
Trpura	635	997	1559	2427
Sub Total	6404	9501	14061	20756
Islands				
Andaman & Nicobar	148	236	374	591
Lakshadweep	28	44	70	111
Total	529013	719097	975222	1318644

The elasticity of electricity consumption with respect to the GDP was 1.10 in the nineties. Assuming a growth of 6% in GDP over the next six years, the elasticity is projected to come down slightly as shown in the Table below.

Table 13.2.3 Elasticity of electricity consumption

Period	2001-2007
Elasticity	1.06

The current installed capacities (as on 31 May 2001) in the states are shown below.

Table 13.2.4 Installed capacity in the states (MW)

State	Sector	Total	Hydel	Coal	Gas	Diesel	Total Thermal	Wind	Nuclear
Northern region									
Delhi	State	617	0	335	282	0	617	0	0
	Private	0	0	0	0	0	0	0	0
	Center	2308	217	1797	207	0	2004	0	87
	Total	2925	217	2132	489	0	2621	0	87
Haryana	State	1990	884	1103	0	4	1106	0	0
	Private	0	0	0	0	0	0	0	0

State	Sector	Total	Hydel	Coal	Gas	Diesel	Total Thermal	Wind	Nuclear
Himachal Pradesh	Center	1290	314	383	534	0	917	0	59
	Total	3280	1198	1486	534	4	2023	0	59
	State	324	324	0	0	0	0	0	0
	Private	0	0	0	0	0	0	0	0
Jammu & Kashmir	Center	239	109	54	62	0	116	0	14
	Total	563	433	54	62	0	116	0	14
	State	417	233	0	175	9	184	0	0
	Private	0	0	0	0	0	0	0	0
Punjab	Center	709	433	114	129	0	243	0	33
	Total	1126	666	114	304	9	427	0	33
	State	4529	2399	2130	0	0	2130	0	0
	Private	0	0	0	0	0	0	0	0
Rajasthan	Center	1216	456	406	264	0	670	0	90
	Total	5745	2855	2536	264	0	2800	0	90
	State	2492	972	1475	39	0	1514	6	0
	Private	1	0	0	0	0	0	1	0
Uttar Pradesh	Center	1942	207	453	358	0	811	0	924
	Total	4434	1179	1928	397	0	2325	7	924
	State	5613	1511	4102	0	0	4102	0	
	Private	0	0	0	0	0	0	0	
Chandigarh	Center	2812	201	2085	482	0	2567	0	44
	Total	8425	1712	6187	482	0	6669	0	44
	State	2	0	0	0	2	2	0	0
	Private	0	0	0	0	0	0	0	0
Central Unallocated	Center	68	33	15	15	0	30	0	5
	Total	70	33	15	15	2	32	0	5
	State	898	40	533	261	0	794	0	64
	Private	1	0	0	0	0	0	1	0
Total Northern Region	Center	11482	2010	5840	2312	0	8152	0	1320
	Total	27466	8332	14985	2808	15	17807	7	1320
Western region									
Goa	State	0	0	0	0	0	0	0	0
	Private	48	0	0	48	0	48	0	0
	Center	407	0	357	35	0	392	0	15
	Total	455	0	357	83	0	440	0	15
Daman & Diu	State	0	0	0	0	0	0	0	0
	Private	0	0	0	0	0	0	0	0
	Center	14	0	8	4	0	12	0	2
	Total	14	0	8	4	0	12	0	2
Gujarat	State	4584	547	3759	243	17	4019	17	0
	Private	2640	0	1060	1430	0	2490	150	0
	Center	1538	0	829	424	0	1253	0	285
	Total	8762	547	5648	2097	17	7763	167	285
Madhya Pradesh	State	4351	913	3438	0	0	3438	1	0
	Private	22	0	0	0	0	0	22	0
	Center	1618	0	1268	257	0	1525	0	93
	Total	5991	913	4706	257	0	4963	23	93
Maharashtra	State	9744	2400	6425	912	0	7337	6	0
	Private	3200	447	1650	920	0	2570	183	0
	Center	2028	0	1339	392	0	1731	0	297
	Total	14972	2847	9414	2224	0	11638	190	297
Dadra & Nagar Haveli	State	0	0	0	0	0	0	0	0

State	Sector	Total	Hydel	Coal	Gas	Diesel	Total Thermal	Wind	Nuclear
	Private	0	0	0	0	0	0	0	0
	Center	16	0	9	5	0	14	0	2
	Total	16	0	9	5	0	14	0	2
Central Unallocated		891	0	650	175	0	825	0	66
Total Western Region	State	18678	3860	13622	1155	17	14794	24	0
	Private	5910	447	2710	2398	0	5108	355	0
	Center	6512	0	4460	1292	0	5752	0	760
	Total	31101	4307	20792	4845	17	25654	379	760
Southern region									
Andhra Pradesh	State	5879	2822	2953	99	0	3052	5	0
	Private	880	0	0	793	0	793	87	0
	Center	1001	0	857	0	0	857	0	144
	Total	7760	2822	3810	892	0	4702	92	144
Karnataka	State	4178	2788	1260	0	128	1388	3	0
	Private	345	18	260	0	25	285	42	0
	Center	674	0	544	0	0	544	0	130
	Total	5197	2806	2064	0	153	2217	45	130
Kerala	State	2032	1795	0	0	235	235	2	0
	Private	186	12	0	174	0	174	0	0
	Center	804	0	398	350	0	748	0	56
	Total	3022	1807	398	524	235	1157	2	56
Tamil Nadu	State	5222	1995	2970	237	0	3207	19	0
	Private	1429	0	0	331	306	636	793	0
	Center	1969	0	1611	0	0	1611	0	358
	Total	8620	1995	4581	568	306	5454	813	358
Pondicherry	State	33	0	0	33	0	33	0	0
	Private	0	0	0	0	0	0	0	0
	Center	142	0	130	0	0	130	0	12
	Total	175	0	130	33	0	163	0	12
Central Unallocated		610	0	530	0	0	530	0	80
Total Southern Region	State	17343	9400	7183	369	363	7914	29	0
	Private	2840	30	260	1298	331	1889	922	0
	Center	5200	0	4070	350	0	4420	0	780
	Total	25383	9430	11513	2016	693	14222	951	780
Eastern region									
Bihar & Jharkhand	State	1988	175	1814	0	0	1814	0	0
	Private	120	0	120	0	0	120	0	0
	Center	2731	84	2557	90	0	2647	0	0
	Total	4839	259	4490	90	0	4580	0	0
West Bengal	State	3582	165	3305	100	12	3417	1	0
	Private	1202	0	1201	0	0	1202	0	0
	Center	1750	60	1690	0	0	1690	0	0
	DVC	263	0	263	0	0	263		
	Total	6797	225	6459	100	12	6796	1	0
Onssa	State	2298	1877	420	0	0	420	1	0
	Private	0	0	0	0	0	0	0	0
	Center	1102	0	1102	0	0	1102	0	0
	Total	3400	1877	1522	0	0	1522	1	0
Sikkim	State	38	33	0	0	5	5	0	0
	Private	0	0	0	0	0	0	0	0
	Center	118	60	58	0	0	58	0	0
	Total	156	93	58	0	5	63	0	0
Central Unallocated		878	0	878	0	0	878	0	0

State	Sector	Total	Hydel	Coal	Gas	Diesel	Total Thermal	Wind	Nuclear
Total Eastern Region	State	7907	2250	5539	100	17	5656	2	0
	Private	1322	0	1321	0	0	1322	0	0
	Center	6842	204	6548	90	0	6638	0	0
	Total	16070	2454	13407	190	17	13615	2	0
North-eastern region									
Assam	State	597	2	330	245	21	595	0	0
	Private	25	0	0	25	0	25	0	0
	Center	349	171	0	178	0	178	0	0
	Total	970	173	330	447	21	798	0	0
Arunachal Pradesh	State	45	30	0	0	16	16	0	0
	Private	0	0	0	0	0	0	0	0
	Center	43	22	0	21	0	21	0	0
	Total	88	52	0	21	16	37	0	0
Meghalaya	State	189	187	0	0	2	2	0	0
	Private	0	0	0	0	0	0	0	0
	Center	70	44	0	26	0	26	0	0
	Total	259	231	0	26	2	28	0	0
Tripura	State	85	16	0	65	5	69	0	0
	Private	0	0	0	0	0	0	0	0
	Center	64	31	0	33	0	33	0	0
	Total	149	47	0	98	5	102	0	0
Manipur	State	13	3	0	0	9	9	0	0
	Private	0	0	0	0	0	0	0	0
	Center	77	50	0	26	0	26	0	0
	Total	89	54	0	26	9	36	0	0
Nagaland	State	6	4	0	0	2	2	0	0
	Private	0	0	0	0	0	0	0	0
	Center	52	33	0	19	0	19	0	0
	Total	58	37	0	19	2	21	0	0
Mizoram	State	37	8	0	0	29	29	0	0
	Private	0	0	0	0	0	0	0	0
	Center	31	15	0	16	0	16	0	0
	Total	68	23	0	16	29	45	0	0
Central Unallocated		119	64	0	56	0	56	0	0
Total North Eastern Region	State	973	250	330	309	84	723	0	0
	Private	25	0	0	25	0	25	0	0
	Center	805	430	0	375	0	375	0	0
	Total	1802	680	330	709	84	1122	0	0
Islands									
Andaman & Nicobar	State	34	0	0	0	34	34	0	0
	Private	0	0	0	0	0	0	0	0
	Center	0	0	0	0	0	0	0	0
	Total	34	0	0	0	34	34	0	0
Lakshadweep	State	10	0	0	0	10	10	0	0
	Private	0	0	0	0	0	0	0	0
	Center	0	0	0	0	0	0	0	0
	Total	10	0	0	0	10	10	0	0
Total Islands	State	44	0	0	0	44	44	0	0
	Private	0	0	0	0	0	0	0	0
	Center	0	0	0	0	0	0	0	0
	Total	44	0	0	0	44	44	0	0

Most states have been experiencing power shortages as shown in the Table below

Table 13.2.5 Power shortages (MW)

State	November, 2001				April, 2001-November, 2001			
	Peak demand	Peak Met	Shortage	%	Peak demand	Peak Met	Shortage	%
Chandigarh	140	140	0	0.0	180	180	0	0.0
Delhi	2645	2481	164	6.2	3040	2879	161	5.3
Haryana	2593	2528	65	2.5	2970	2900	70	2.4
H. P.	519	519	0	0.0	540	519	21	3.9
J & K	1179	909	270	22.9	1179	991	188	15.9
Punjab	3775	3525	250	6.6	5420	4936	484	8.9
Rajasthan	3603	3603	0	0.0	3603	3603	0	0.0
U.P.	7492	6887	605	8.1	7584	6887	697	9.2
Chattisgarh	1336	1277	59	4.4	1357	1311	46	3.4
Gujarat	7894	6498	1396	17.7	7894	6700	1194	15.1
M.P.	5313	4457	856	16.1	5313	4457	856	16.1
Maharashtra	12052	10458	1594	13.2	12200	10458	1742	14.3
Goa	259	259	0	0.0	293	293	0	0.0
A.P.	6549	5741	808	12.3	7622	6283	1339	17.6
Karnataka	4604	3985	619	13.4	5321	3985	1336	25.1
Kerala	2591	2185	406	15.7	2591	2189	402	15.5
Tamil Nadu	6682	5718	964	14.4	6900	5843	1057	15.3
Bihar	1349	1203	146	10.8	1356	1288	68	5.0
D.V.C.	1225	1124	101	8.2	1296	1209	87	6.7
Orissa	1983	1883	100	5.0	1983	1883	100	5.0
West Bengal	3499	3397	102	2.9	3614	3414	200	5.5
Arunachal Pr.	48	47	1	2.1	50	50	0	0.0
Assam	596	583	13	2.2	688	618	70	10.2
Manipur	94	94	0	0.0	98	94	4	4.1
Meghalaya	137	136	1	0.7	137	136	1	0.7
Mizoram	73	73	0	0.0	73	73	0	0.0
Nagaland	50	50	0	0.0	61	58	3	4.9
Tripura	133	113	15	15.0	156	140	16	10.3
All India	75007	67498	7509	10.0	77956	67663	10293	13.2

We do not expect any great improvement in the situation by 2006/7. We have assumed that existing shortages in energy supply will continue and have calculated the required generation capacity on that basis. To that end, we have made three assumptions discussed below:

T&D losses

The 16th EPS has assumed some improvement in T&D losses in the states as shown in the Table below.

Table 13.2.6 Improvement in T&D losses

All India and Statewise - Transmission and distribution losses (%)						
State	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05
	Estimated					
Haryana	32.8	32.6	32.2	31.8	31.4	31
Himachal Pradesh	25.3	25.2	25.1	25	24.9	24.8
Jammu & Kashmir	46.5	45.5	44.5	43.5	42.5	41.5
Punjab	18.84	18.75	18.66	18.57	18.48	18.36
Rajasthan	24.6	24.5	24.4	24.3	24.2	24.1
Uttar Pradesh	26.3	26.1	25.9	25.7	25.5	25.3
Chandigarh	30	29.5	29	28.5	28	27.5
Delhi	47.8	46.8	45.8	44.8	43.8	42.8
Goa	27.25	27	26.75	26.5	26.25	26
Gujarat	21.46	21.14	20.81	20.48	20.16	19.83
Madhya Pradesh	20.2	20.1	20	19.9	19.8	19.7
Maharashtra	16.82	16.75	16.69	16.62	16.55	16.47
Dadra & Nagar Haveli	11.2	11.1	11	10.9	10.8	10.7
Daman & Diu	8.43	8.42	8.54	8.54	8.48	8.55
Andhra Pradesh	31.1	29.6	28.1	26.1	24.1	22.1
Karnataka	18.9	18.8	18.7	18.6	18.5	18.4
Kerala	20.7	20.5	20.3	20.1	19.9	19.7
Tamil Nadu	16.9	16.81	16.71	16.63	16.55	16.65
Pondicherry	13.21	13.21	13.22	12.82	12.79	12.81
Bihar	16.21	16.25	16.31	16.39	16.48	16.53
Orissa	24.5	24	23.5	23	22.5	22
Sikkim	20	20	20	20	20	20
West Bengal	21.18	20.93	20.71	20.49	20.27	20.05
Arunachal Pradesh	29.51	28.86	28.42	28.14	27.38	27.03
Assam	23	23	22.9	22.8	22.7	22.6
Manipur	21.28	21.21	21.05	20.99	20.94	20.77
Meghalaya	26.69	26.44	26.14	25.84	25.5	25.23
Mizoram	39	37	35	33	31	29
Nagaland	34.38	33.91	33.54	32.98	31.99	31.03
Tripura	30.5	30	29.5	29	28.5	28
All India	23.14	22.83	22.53	22.14	21.77	21.41

We have assumed a further improvement of 2% in the T&D losses by 2006-07. We feel justified in making this assumption as electricity sector regulators have been appointed in most states and the regulators have put considerable stress on loss reduction.

PLF

With little additional capacity coming in, the pressure on existing plants would be high and their performance is bound to improve. This has been the experience in the nineties. We assume that the PLF of all existing plants and the new plants will improve by 5% over the level usually assumed by CEA.

Captive generation

Captive generation has increased rapidly in the nineties. Large industries account for most of captive power generation. The growth in captive generation would depend on the growth rate in industrial production and the price of power paid by the industry to the utilities. These prices are high because of the cross-subsidy between sectors. The cross-subsidies are being phased out. This should result in a reduction of power prices for the industry and therefore a reduction in captive generation. The 16th EPS has projected the growth of captive generation upto 2004/5. We have used the same growth rate to project the captive generation in 2006/7. This is shown in the Table below.

Table 13.2.7 Growth in captive generation (MKwh)

States	1999/00	2004-05	2006/07
Haryana	835	1178	1352
Himachal Pradesh	75	110	128
Jammu & Kashmir	1	1	1
Punjab	381	601	721
Rajasthan	1423	1573	1637
UP	6141	8050	8971
Chandigarh	2	2	2
Delhi	100	130	144
Goa	95	95	95
Gujarat	6766	7927	8445
Madhya Pradesh	4891	5079	5156
Maharashtra	1490	1539	1559
D & N Haveli	31	36	38
Daman & Diu	-	-	-
Andhra Pradesh	5541	6223	6519
Karnataka	2393	2731	2879
Kerala	612	793	880
Tamil Nadu	2412	2526	2573
Pondicherry	14	14	14
Bihar (excl DVC)	2935	2972	2987
Orissa	7086	12520	15721
Sikkim	-	-	-
West Bengal	1041	1451	1657
Arunachal Pradesh	-	-	-
Assam	679	698	706
Manipur	-	-	-
Meghalaya	-	-	-
Mizoram	-	-	-
Nagaland	2	2	2
Trpura	-	-	-
Andaman & Nicobar	1	1	1
Lakshadweep	0	0	0
All India	44947	56252	62189

CEA has recently drawn up a list of power projects which could be set up in the Tenth Plan (2002-07). These projects add up to a capacity of 47,000 MW. Over the last two five year plans we have added slightly less than 20,000 MW in each plan period. It is highly unlikely that 47,000MW will be added in the next five years. We have accordingly assumed that only the sanctioned and ongoing (SOG) schemes in the CEA's list will be commissioned by 2006/7.

Table 13.2.8 bring out the position in 2006/7.

Table 13.2.8 Power deficit position in 2006/7

States	Energy requirement 16th EPS 2006/07 (MU)	Existing shortages (%)	Shortages (MU)	Net after shortages (MU)	Improvement in T&D (MU)	Net Requirement (MU)	Captive (MU)	Net after captive (MU)	Energy available (State+Private) (MU)	Deficit (MU)	Energy available (Central) (MU)	Net Deficit (MU)	90% of Net Deficit (MW)
Haryana	25750	2.8	721	25029	501	24528	1352	23177	16793	6384	3814	2570	326
Punjab	41922	2.7	1132	40790	816	39974	721	39253	32186	7067	4222	2845	361
Rajasthan	40341	3.6	1452	38889	778	38111	1637	36474	26125	10349	6182	4166	528
Uttar Pradesh	70803	14.6	10337	60466	1209	59256	8971	50286	42737	7548	4509	3039	385
Delhi	25672	4.9	1258	24414	488	23926	144	23781	19004	4777	2854	1923	244
Goa	2207	10.8	238	1969	39	1929	95	1834	1576	258	136	122	16
Gujarat	61683	9.7	5983	55700	1114	54586	8445	46140	53716	0	0	0	0
Madhya Pradesh	51952	12.4	6442	45510	910	44600	5156	39444	36577	2866	1508	1358	172
Maharashtra	106892	10.5	11224	95668	1913	93755	1559	92196	71184	21012	11053	9959	1263
Andhra Pradesh	68797	7.8	5366	63431	1269	62162	6519	55643	51857	3787	1327	2460	312
Karnataka	44748	9.1	4072	40676	814	39862	2879	36983	28786	8197	2873	5324	675
Kerala	22998	6.6	1518	21480	430	21051	880	20171	13239	6932	2430	4503	571
Tamil Nadu	54872	7.6	4170	50702	1014	49688	2573	47115	40116	6999	2453	4546	577
Bihar (excl DVC)	12256	7	858	11398	228	11170	2987	8183	8702	0	0	0	0
DVC	11129	-1.7	-189	11318	226	11092	0	11092	8510	2582	4755	0	0
Orissa	17997	-3.1	-558	18555	371	18184	15721	2463	12070	0	0	0	0
West Bengal (excl DVC)	27846	-0.9	-251	28097	562	27535	1657	25878	19115	6763	12455	0	0
Arunachal Pradesh	303	-1.9	-6	309	6	303	0	303	130	172	173	0	0
Assam	5294	-7.8	-413	5707	114	5593	706	4887	3856	1031	1031	0	0
Manipur	1039	2.3	24	1015	20	995	0	995	45304	0	0	0	0
Meghalaya	955	-7.3	-70	1025	20	1004	0	1004	605	399	399	0	0
Mizoram	525	-2.7	-14	539	11	528	0	528	309	220	220	0	0
Nagaland	388	-2.6	-10	398	8	390	2	388	336	52	52	0	0
Tripura	997	-3.9	-39	1036	21	1015	0	1015	596	419	419	0	0
Total	697366		53247	644119	12882	631237	62005	369232	533431	97813	62863	42815	5431

In 2006/7, there would be a shortfall of 42815 MU even after the SOG projects are commissioned. This could be supplied by 5431 MW of new capacity working at a PLF of 90%. It is too late now to set up coal based or hydroelectric units to meet this deficit but gas based units could still be set up and we have counted this in computing the gas demand in 2006/7.

The gas demand in 2006/7 from the power sector would have the following elements:

- Demand from existing gas based units - 42.76 MMCMD

(This is the gas allocated to these units)

- Demand from existing naphtha/diesel based units - 6.61 MMCMD
- Demand from SOG gas/naphtha (Annexure-2.2) - 1.18 MMCMD
- Demand from possible units to meet deficit (Annexure 2.3)– 21.24 MMCMD

Total demand- 71.79 MMCMD

In planning the capacity for 2006/7, we have not considered the peak load, assuming that peaking shortages would remain. Meeting these shortages would require even higher capacities to be installed and that is plainly unlikely. We have also not considered the retirement of existing plants as we believe the old plants would be covered under R&M schemes and would not be retired when new capacity is in short supply. At present, there is only a limited amount of inter-state trade in power. In calculating the statewise gas demands, we have accordingly assumed that the power required by a state would be generated within the state.

Many of our assumptions regarding T&D losses, PLF, captive generation, etc. would depend critically on the regulatory regimes in the states. One of the tasks before the regulators is to rationalise power tariffs. This would have its effect on demand although the price elasticity of demand would be low. More importantly, tariff reforms would determine the ability of SEBs to pay for power, or to enter into long term take-or-pay contracts. As yet there is considerable uncertainty on the progress of regulatory reforms. To that extent, the gas demand projections also are uncertain.

The statewise break-up of the gas demand for power generation is shown below.

Table 13.2.9 Gas demand for power generation (MMCMD)

State	2006
Northern region	
Delhi	4.38
Uttar Pradesh	6.63
Punjab	1.41
Rajasthan	5.06
Haryana	3.24
Sub Total	20.72
Western region	
Goa	0.06
Gujarat	10.56
Madhya Pradesh	0.67
Maharashtra	10.94
Sub Total	22.23
Southern region	
Andhra Pradesh	10.67
Karnataka	3.24

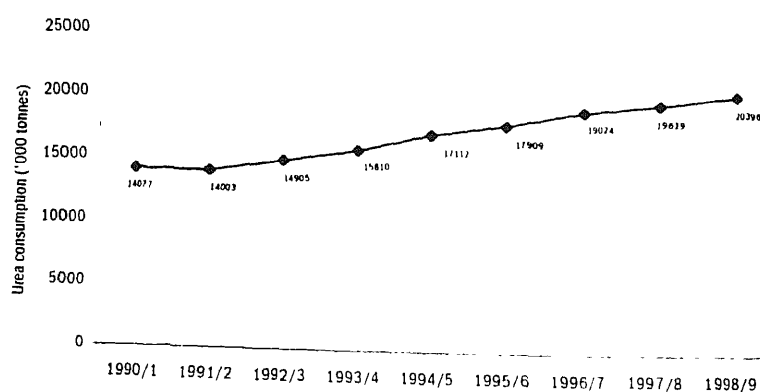
State	2006
Kerala	4.91
Tamil Nadu	6.98
Sub Total	25.80
Eastern region	
Orissa	0.00
West Bengal	0.05
Bihar & Jharkhand	0.00
Sub Total	0.05
North eastern region	
Arunachal Pradesh	0.06
Assam	1.10
Manipur	0.04
Meghalaya	0.01
Mizoram	0.11
Nagaland	0.01
Tripura	1.67
Sub Total	2.99
All India Total	71.79

Production of urea

Seventy-five per cent of the fertilizer used in India is used in the production of foodgrains, namely, rice, wheat, pulses and sugarcane. Eighty-five per cent of the nitrogen required is applied in the form of urea. The nutrients - N, P and K - are ideally used in the proportion of 5.9.2.4:1. However, since 1992, N has been applied in excess owing to the price control on urea. It is expected that this distortion would be corrected when the urea price is decontrolled. The intensity of fertilizer use in India is low at 75 kg/hectare as very little fertilizer is used in non-irrigated lands.

Urea consumption in the country has increased at an annual rate of about 5% from 14 million tonnes in 1990/91 to 20 million tonnes in 1998/99 as shown below.

Figure 13.2.1 Urea consumption in India



Source: Fertilizer Association of India

While most of the urea consumed in the country has been produced domestically, a part of the requirement has been imported. Urea consumption and imports over the past decade is in the Table below.

Table 13.2.10 Urea imports by India (1991-99)

Year	Urea consumption (million tonnes)	Urea imports (million tonnes)	Imports as % of consumption
1991-92	14.00	0.39	3
1992-93	14.91	1.86	12
1993-94	15.81	2.84	18
1994-95	17.11	2.88	17
1995-96	17.91	3.78	21
1996-97	19.02	2.33	12
1997-98	19.62	2.39	12
1998-99	20.40	0.56	3

Source. Fertilizer Association of India

Over the last two years, the consumption of urea has not shown any growth and the import has dropped to zero last year.

The import price of urea has fluctuated widely, sharply increasing whenever India and China increased their imports. The international prices since 1970 are shown in the Table below.

Table 13.2.11 International urea prices

Year	Price at current \$ (per MT)	Year	Price at current \$ (per MT)	Year	Price at current \$ (per MT)
1971	46.00	1980	222.10	1989	132.20
1972	59.30	1981	216.00	1990	157.00
1973	94.80	1982	158.80	1991	172.00
1974	315.80	1983	135.40	1992	140.30
1975	198.00	1984	171.30	1993	106.75
1976	112.00	1985	136.30	1994	147.92
1977	127.40	1986	107.00	1995	211.50
1978	144.80	1987	116.60	1996	205.48
1979	172.90	1988	155.00	1997	103.00
				1998	91.00

Source. EPW July 1999

The long-term average cif price at Mumbai works out to \$150/MT.

Urea demand projections

Fertilizer demand projections are based on projections of growth in agricultural production. The agriculture sector has faced some major problems after the economic reforms of the early nineties. The production actually decreased in

1995-96 and 1997-98. The overall growth rate in foodgrains production in the nineties was 2.7%. The Fertilizer Association of India (FAI) estimates that the foodgrain production in India in 2011/12 will reach 340 million tonnes. This implies a growth rate of 4% over 1999-2012. There is some uncertainty at present as to the impact that the WTO agreements would have on agriculture. There could be a major shift from crops grown for self-consumption to cash crops and exportable crops. However, these factors can be taken into account only after more information becomes available and we have adopted the FAI estimates of foodgrain production.

To project the fertilizer requirement in 2011-12, we assume that one ton of fertilizer increases foodgrain production by 10 tonnes. This is higher than a figure of 7.5 tonnes also adopted in some forecasts but we assume that improvements in water management expected in future would make the higher yields possible. The foodgrains production in 1998-99 was 204 million tonnes. An increase of 136 million tonnes of foodgrains would require an additional 13.6 million tonnes of all fertilizers. Assuming that foodgrains will account for 75 per cent of fertilizer consumed as at present, the total additional requirement would be 18 million tonnes in terms of N, P and K, with the additional urea requirement of 20.7 million tonnes. Adding this to the consumption of 20.4 million tonnes in 1998-99, we get a requirement of 41.1 million tonnes of urea by 2011-12.

Likely production capacity

It is, of course, not necessary to produce all the urea domestically. However, the government would like to restrict the imports on grounds of food security. Keeping imports down to the level of 20% of consumption would mean that we produce 33 million tonnes by 2012. The current production capacity is around 20 million tonnes. Pending a detailed exercise to estimate future urea demand, the government has decided not to approve any new urea plant before 2003. The proposals for four new plants with a total capacity of 3 million tonnes at Thal, Nellore, Gorakhpur and Hazira were pending for government approval at the time the ban on new capacity was imposed. These plants are likely to be cleared after 2003 and could be set up in the 2008-10 period. A joint venture project with the Oman Oil Company for a 1.5 million tonnes unit in Oman is also at an advanced stage of discussion.

However, considering time period of this study till 2006/7, we expect no new expansion plants to be commissioned within this time frame.

Choice of feedstock and potential gas demand

The oldest urea plants in the country were based on coal and fuel oil. These are now practically defunct. The plants set up in the 70's and 80's were based on naphtha. In the late 80's and the 90's, natural gas from the western offshore fields was made available through the HBJ pipeline and a number of gas based urea plants were set up.

Under the existing controlled price regime for urea, the urea producers are allowed retention prices, which compensate them fully for their capital costs and variable costs including the cost of feedstock. The urea plants based on different feedstocks do not have to compete against each other. Urea is sold on the basis of linkages decided by the government, the cost of transport from the plant to the consumption point being met by the government. A maximum price of Rs. 4,600/MT is payable by the farmers no matter where they are located.

In these circumstances, the feedstock choice is guided by availability and not the price. However, the present arrangement is proving to be costly for the government. As the average cost of production is greater than the retail price of urea, the deficit has to be met by a government subsidy. The burden of fertilizer subsidies on the budget of central government has grown dramatically over the years from Rs. 505 crores in 1980/81 to Rs. 13,244 crores in 1999/00. Driven by the need to contain the increasing subsidy, the government is considering a phased decontrol of urea prices. The Expenditure Reforms Commission has recommended a complete decontrol of the urea price by April 2006. Earlier attempts by the government to decontrol the urea price were not successful and it is not clear if the government can implement this recommendation.

Conversion from naphtha

Once the urea price is decontrolled, the urea producers will have to compete against each other and also against imports. The import of urea is now canalized but under the WTO Agreement, urea will have to be put under OGL. The domestic industry may then be protected by a suitable tariff. The government has appointed a task force to examine the feasibility of setting up new coal based urea plants. However, such plants are not expected soon. Domestic gas and LNG would be the natural choice for feedstock to the extent they are available. No new naphtha based plant is likely to be put up and the existing naphtha based plants would have to change over to gas in order to survive. Even if the urea price is not decontrolled, the government would persuade these units to change to LNG as soon as it is available in order to reduce the fertiliser subsidy.

Naphtha is now under OGL and it can be imported by anyone. Naphtha produced domestically is now sold at import parity prices. Naphtha is both imported and exported. Nearly 2 million tonnes of naphtha was exported last year. With new refinery capacity planned to be set up, the surplus of naphtha would increase. A part of this surplus naphtha may be converted into gasoline but a part of it would have to be exported. In such a situation, inland refineries in north India such as Mathura, Panipat and Bhatinda may drop their prices to export parity levels. Even then, naphtha based urea producers would find it economical to change to gas.

The existing naphtha based urea producers are listed in the Table below.

Table 13.2.12 Existing naphtha based urea units

Urea Units	State	Capacity ('000 tonnes)
CFL	Andhra Pradesh	346.0
Chambal Fertilisers, Unit II	Rajasthan	775.5
Duncans Industries	Uttar Pradesh	675.0
FACT, Ambalamedu, Unit I	Kerala	330.0
HFC, Barauni	Bihar	184.0
HFC, Durgapur	West Bengal	173.0
IFFCO, Phulpur	Uttar Pradesh	1221.0
Unit I		495.0
Unit II		726.0
MFL, Manali	Tamil Nadu	486.0
MCFL, Mangalore	Karnataka	340.0
NFL, Nangal I & II	Punjab	330.0
SFC, Kota	Rajasthan	330.0
SPIC, Tuticorin	Tamil Nadu	512.0
ZIL, Zuannagar	Goa	340.0
Naphtha based urea capacity (existing)		6042.5

Converting these units to gas would require a supply of 13.87 MMCMD. We assume these conversions can be completed by 2006/7.

Table 13.2.13 Gas demand by 2006/7

	Existing units	Conversion from naphtha	Expansion	Total
2006/07	26.35	13.87	Nil	40.22

The statewise break-up of the above demand is shown below.

Table 13.2.14 Statewise breakup of gas demand for urea production

State	2006/7
Northern region	
Punjab	0.81
Uttar Pradesh	12.82
Rajasthan	4.16
Sub Total	17.79
Western region	
Goa	0.83
Gujarat	5.51
Madhya Pradesh	3.22
Maharashtra	4.20
Sub Total	13.76
Southern region	
Andhra Pradesh	3.25
Kerala	0.81
Tamil Nadu	2.22
Karnataka	0.83
Sub Total	7.11
Eastern region	
Bihar	0.56
West Bengal	0.54
Sub Total	1.10
North eastern region	
Assam	0.45
Tripura	0.00
Sub Total	0.45
All India Total	40.22

Industry

Gas is now used by a wide variety of industrial units including sponge iron, glass and ceramics, paper, sugar, textile and chemical units. On account of the low international price of scrap iron, no new gas-based sponge iron unit has been set up in recent years. Additional capacity is coming from small coal-based units only. Accordingly, the sponge iron industry has also not been considered for calculating the gas demand. The sugar industry is not likely to take large volumes of gas as most of their fuel need is met by bagasse. Up to date data on the textile and chemical units is not available and demand from these sectors has to be established by a detailed survey. The cement industry does not at present consume any gas but this is a promising sector, which could absorb large volumes if the technology is suitably upgraded. We have accordingly computed the potential demand from the cement, paper and glass/ceramics industry.

The cement industry

The installed capacity of cement units, as of March 2000, is available from the Cement Statistics 2000 compiled by the Cement Manufacturers' Association (CMA). The total capacity of large cement plants (capacity of 2 million tonnes or more) is shown in the Table below.

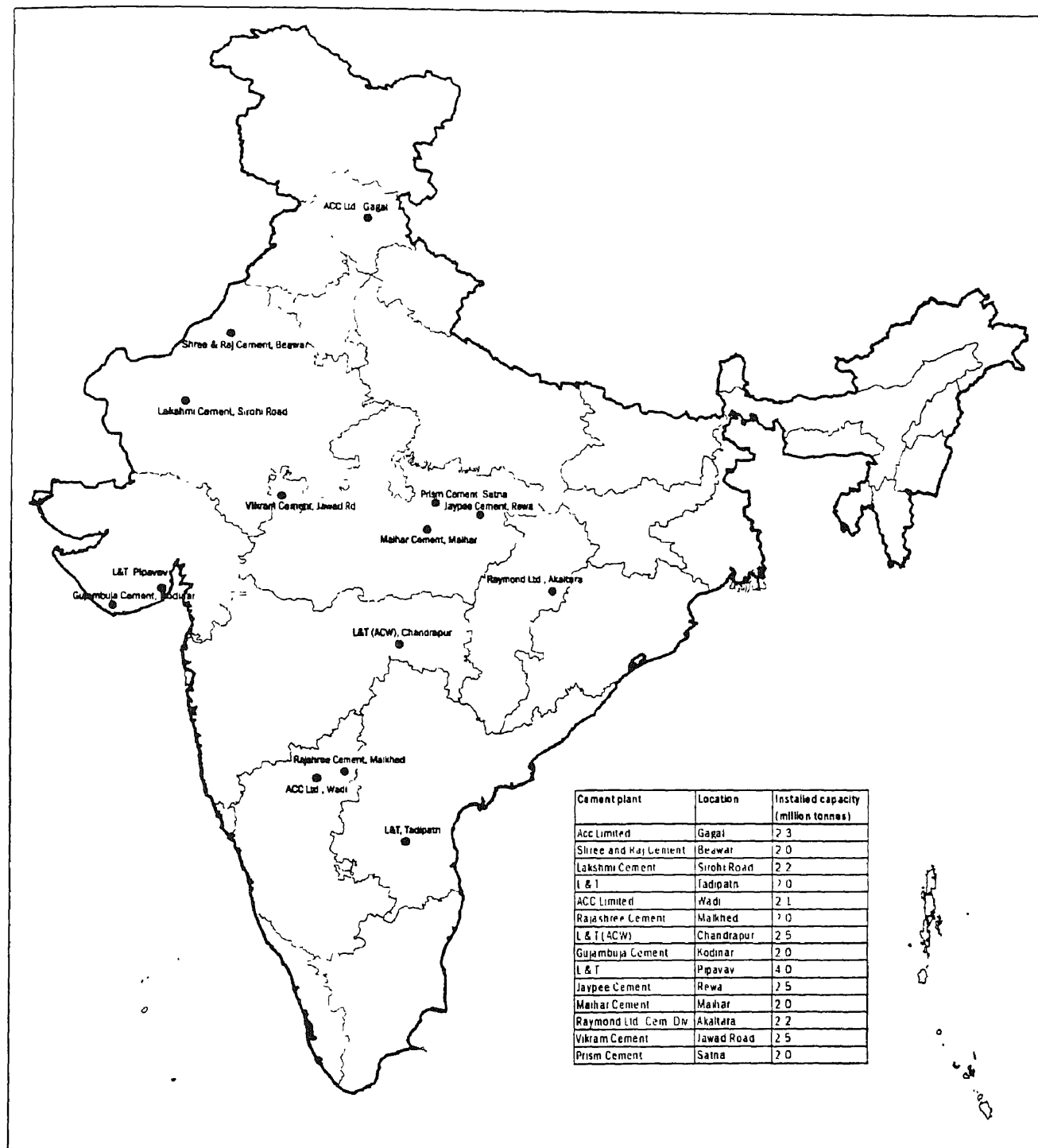
Table 13.2.15 Installed capacity of large cement units (million tonnes)

State	Installed Capacity (million tonnes)
Himachal Pradesh	2.3
Rajasthan	4.2
Gujarat	6.0
Madhya Pradesh	11.2
Maharashtra	2.5
Andhra Pradesh	2.0
Karnataka	4.1
Total	32.3

Source. Cement Manufacturers' Association

The cement plant clusters have been mapped as shown below.

Map 13.2.1 Cement units with installed capacity of 2 million tonnes or more



Capacity utilization in the cement industry is about 86%. Most of the cement production in India uses the dry process. According to the CMA, the energy consumption ranges from 800 – 1060 kcals/kg of cement. An average of 930 kcals/kg has been used for evaluating the energy requirement for cement production in the states. Consequent gas demand has been estimated using a gas calorific value of 8500 kcal/m³. The plants of Madhya Pradesh have not been considered as they are too close to coalfields. Also the plant in Himachal Pradesh has not been considered as it is too remote. We have assumed a 6% growth rate in production in consultation with the industry. Only the largest units have been considered as these may change to gas more readily. The results are in the Table below.

Table 13.2.16 Estimation of gas demand for cement industry

	Unit	2000	2006
Total installed capacity in India	million tonnes	110.1	
Total cement production in India	million tonnes	94.21	
Production as a % of installed capacity	%	86	
Total capacity considered	million tonnes	18.78	
Total production considered	million tonnes	16.15	
Energy requirement for cement production	kcal/kg	930	
Total energy requirement in states	Million kcal	15020244	21306503
Calorific value of gas	kcal/m ³	8500	8500
Gas demand	MMCMD	4.84	6.87

The statewise break-up of the above demand is shown below.

Table 13.2.17 Statewise break up of gas demand in cement industries

		Rajasthan	Gujarat	Maharashtra	Andhra Pradesh	Karnataka	Total
Total capacity considered	million tonnes	4.23	6.00	2.50	2.00	4.05	18.78
Total production considered	million tonnes	3.64	5.16	2.15	1.72	3.48	16.15
Gas demand 2000	MMCMD	1.09	1.55	0.64	0.52	1.04	4.84
Gas demand 2006	MMCMD	1.55	2.19	0.91	0.73	1.48	6.87

The paper and pulp industry

The installed capacity of paper and pulp units, as of 1998/99, is available from INPAPER Protech Directory of Indian Paper Manufacturers & Allied Industry. Installed capacities of the 10 largest units from each state have been considered and the corresponding total capacity shown below.

Table 13.2.18 Installed capacity of large paper and pulp units (tonnes per annum)

State	Installed Capacity
Andhra Pradesh	317500
Assam	200000
Gujarat	150000
Maharashtra	225000
Punjab	186480
Tamil Nadu	180000
Uttar Pradesh	186480
Total	1445460

Source. Indian Paper Manufacturers and Allied industry

The paper mill clusters (with capacities of 50,000 tonnes and above) in India have been shown in Map 13.2.2.

Map 13.2.2 Large paper units with capacity of 50,000 tonnes and above



According to industry experts, capacity utilization in the paper and pulp industry is about 70%–80%. An average of 75% has been considered for our analysis. Production has been projected to 2006/7 using an annual growth rate of 6% based on discussion with the industry. A survey done by TERI in 1995 in various states of India estimated that the average energy consumption is 9590 kcal/kg of paper production. The energy required to meet the projected production to 2006 is translated into gas demand using a calorific value of 8500 kcal per cubic metre of gas. Only the units with capacities of 100,000 tonnes per annum and above have been considered. The results are in the Table below.

Table 13.2.19 Gas demand from paper and pulp industry

	Unit	1999	2006
Total installed capacity considered	Tonnes	1445460	
Production as a % of installed capacity	%	75	
Production considered	Tonnes	1084095	
Energy requirement for cement production	kcal/kg	9590	
Total energy requirement in states	Million kcal	10396471	15632448
Calorific value of gas	kcal/m ³	8500	8500
Gas demand (units >=100,000 TPA)	MMCMD	3.35	5.04

The statewise break-up of the above demand is shown below.

Table 13.2.20 Statewise break up of gas demand in paper and pulp industry (MMCMD)

State	1999	2006
Northern region		
Punjab	0.43	0.65
Uttar Pradesh	0.43	0.65
Sub Total	0.86	1.30
Western region		
Gujarat	0.35	0.52
Maharashtra	0.52	0.78
Sub Total	0.87	1.30
Southern region		
Andhra Pradesh	0.74	1.11
Tamil Nadu	0.42	0.63
Sub Total	1.16	1.74
North eastern region		
Assam	0.46	0.70
Sub Total	0.46	0.70
Total	3.35	5.04

Glass units

Industrial use of Liquefied Petroleum Gas (LPG) is mainly by glass units. Gas demand from the glass industry can be estimated by converting LPG consumption on calorie equivalence.

Bulk LPG sales have been projected to 2006 using an annual growth rate of 6%. The corresponding gas demand projections are shown below.

Table 13.2.21 Gas demand from glass industry

	Unit	2000	2006
Bulk LPG sales	tonnes	512870	727516
Caloric value of LPG	kcal/kg	11300	11300
Energy requirement	Million kcal	5795433	8220933
Caloric value of gas	kcal/m ³	8500	8500
Gas demand	MMCMD	1.87	2.65

The statewise break up of gas demand in glass industries has been tabulated below.

Table 13.2.22 Statewise break up of gas demand in glass industry (MMCMD)

States	2000	2006
Northern region		
Delhi	0.32	0.45
Uttar Pradesh	0.56	0.79
Punjab	0.20	0.28
Rajasthan	0.13	0.18
Haryana	0.13	0.19
Sub Total	1.34	1.89
Western region		
Goa	0.01	0.01
Gujarat	0.13	0.19
Madhya Pradesh	0.02	0.03
Maharashtra	0.20	0.28
Sub Total	0.36	0.52
Southern region		
Andhra Pradesh	0.02	0.03
Karnataka	0.02	0.03
Kerala	0.07	0.10
Tamil Nadu	0.02	0.03
Sub Total	0.13	0.19
Eastern region		
Orissa	0.00	0.00
West Bengal	0.02	0.03
Bihar & Jharkhand	0.01	0.01
Sub Total	0.03	0.05
North eastern region		
Arunachal Pradesh	0.00	0.00
Assam	0.00	0.00
Manipur	0.00	0.00

States	2000	2006
Meghalaya	0.00	0.00
Mizoram	0.00	0.00
Nagaland	0.00	0.00
Tripara	0.00	0.00
Sub Total	0.00	0.01
All India Total	1.87	2.65

The gas demand projections for the industrial sector as a whole is worked out in the Table below.

Table 13.2.23 Gas demand from industries (MMCMD)

Industry	Existing	2006
Cement	4.84	6.87
Paper and pulp	3.35	5.04
Glass	1.87	2.65
Total	10.06	14.56

Comments on the demand estimate

In the above analysis we have left out the textile and chemical units in the absence of reliable data. The cement industry, which has the potential of using the largest amount of gas, does not use any gas at present. Only the very large, modern units can change to gas. Even that would require efforts in introducing the technology.

Gas could be used more efficiently than alternative fuels are at present. This means equating the calorie values would overestimate the gas demand.

Unlike cement units, paper and glass units in India are already using gas but improved technology is required if these units have to use costlier imported gas.

Up to date information on industrial units is hard to come by. The gas demand from industrial units can be much better estimated through field surveys.

Captive power generation

The need for captive power generation has increased over the years. The dependence on captive power generation is the highest in the industrial sector and the main contributing factors have been the following:

- Non-availability of adequate grid supply
- Poor quality and reliability of grid supply
- High tariff as a result of heavy cross-subsidization.

Policy on captive generation

Captive capacity deprives the utilities from revenue from the sale of power. This is all the more important because non-industrial tariffs are lower than the cost of supply. Many state governments have, therefore, discouraged captive capacity. However, it has been difficult to maintain such a stand in the face of growing power shortages. The other factor favouring captive capacity is the possibility of cogeneration and using renewable sources like wind energy. The central government has recently released a policy on captive power exhorting the states to encourage captive generation. Most state governments have announced their captive power policy laying down the price payable for surplus power, wheeling charges, norms for banking of power, etc.

Installed captive capacity

Captive capacity is not reported by either the State Electricity Boards or the Central Electricity Authority. Data is available only for 1997-98 and 1998-99, compiled by Powerline Research. The publisher has explained that it is not a complete compilation and that it is based on data made available by the SEBs. The publisher estimates that unreported captive capacity could amount to as much as 40% of the capacity reported. The fuelwise break up of captive capacities in the states as reported by Powerline Research is shown in the Tables below.

Table 13.2.24 Captive capacity by fuel type in 1997-98 (MW)

State	Steam	Diesel	Gas/Naphtha	Hydel	Total
Andhra Pradesh	619	556	45	0	1220
Assam	NA	NA	NA	NA	NA
Bihar	523	92	0	0	614
Delhi	NA	NA	NA	NA	NA
Gujarat	391	149	965	0	1505
Haryana	70	206	60	0	335
Himachal Pradesh	0	32	0	0	32
Jammu & Kashmir	0	3	0	0	3
Karnataka	360	675	0	10	1045
Kerala	0	139	0	12	151
Madhya Pradesh	742	579	11	0	1333
Maharashtra	14	229	326	0	570
Meghalaya	NA	NA	NA	NA	NA
Orissa	1360	155	28	0	1544
Punjab	62	249	0	0	311
Rajasthan	138	345	46	0	528
Tamil Nadu	134	973	0	0	1107
Uttar Pradesh	854	90	296	0	1240
West Bengal	361	403	21	0	786
Total	5627	4874	1799	22	12322

Source. 1999 Captive Report (Powerline)

Table 13.2.25 Captive capacity by fuel type in 1998-99 (MW)

State	Steam	Diesel	Gas/Naphtha	Hydel	Other	Total
Andhra Pradesh	690	576	45	2	0	1312
Assam	65	25	219	0	0	309
Bihar	534	92	0	0	0	625
Delhi	NA	NA	NA	NA	NA	NA
Gujarat	428	256	1076	0	90	1850
Haryana	69	214	60	0	0	343
Himachal Pradesh	0	31	0	0	0	31
Jammu & Kashmir	0	3	0	0	0	3
Karnataka	552	697	0	10	0	1259
Kerala	0	164	3	12	0	178
Madhya Pradesh	800	680	11	0	4	1495
Maharashtra	60	273	330	0	45	708
Meghalaya	NA	NA	NA	NA	NA	NA
Orissa	1447	157	28	0	0	1632
Punjab	76	419	0	0	0	495
Rajasthan	162	356	46	0	9	573
Tamil Nadu	218	1596	0	0	0	1814
Uttar Pradesh	854	124	296	0	0	1275
West Bengal	361	419	21	0	0	801
Total	6317	6081	2135	24	148	14705

Source: 1999 Captive Report (Powerline)

Potential gas demand

Captive generation in 2006/7 have been projected using the growth rate projected over 1999/2000 to 2004/5 in the 16th EPS (Table 13.2.7). It has been assumed that captive gas based generators would operate as open cycle plants with an efficiency of 35%.

Captive generation based on coal and diesel is not convertible to gas but the naphtha based capacity can be converted. So far as new units are concerned, we assume that the share of steam and hydel remains the same and that all other capacity will be gas based.

With these assumptions, the gas demand works out as below:

Table 13.2.26 Gas demand for captive generation

	Unit	1999/00	2006/7
Captive generation	MU	44823	
Additional captive generation	MU		16526
Captive gas based generation	MU	7279	
Additional captive gas based generation	MU		5779
Existing gas demand (including conversion of naphtha)	MMCMD	5.78	
Additional gas demand	MMCMD		4.59
Total gas demand	MMCMD	5.78	10.36

The statewise break-up of the above demand is shown below.

Table 13.2.27 Statewise break up of gas demand for captive generation (MMCMD)

State	1999/00	2006/07
Northern region		
Haryana	0.12	0.44
Punjab	0.00	0.23
Rajasthan	0.09	0.21
Uttar Pradesh	1.13	1.87
Delhi	0.00	0.04
Sub Total	1.34	2.79
Western region		
Goa	0.08	0.08
Gujarat	3.12	4.15
Madhya Pradesh	0.03	0.13
Maharashtra	0.55	0.60
Sub Total	3.78	4.95
Southern region		
Andhra Pradesh	0.15	0.52
Karnataka	0.00	0.21
Kerala	0.01	0.21
Tamil Nadu	0.00	0.11
Sub Total	0.16	1.05
Eastern region		
Bihar	0.00	0.01
Orissa	0.10	0.87
West Bengal	0.02	0.29
Sub Total	0.12	1.17
North eastern region		
Arunachal Pradesh	0.00	0.00
Assam	0.38	0.40
Manipur	0.00	0.00
Meghalaya	0.00	0.00
Mizoram	0.00	0.00
Nagaland	0.00	0.00
Tripura	0.00	0.00
Sub Total	0.38	0.40
Total	5.78	10.36

Putting together the sectoral gas demands, we get the total demand as shown below.

Table 13.2.28 Total gas demand (MMCMD)

	Existing	2006/7
Power	49.37	71.79
Fertiliser	40.22	40.22
Industries*	10.06	14.56
Captive	5.78	10.36
Total	105.43	136.93

* Does not include industries other than cement, paper and glass.

Annexure 13.3 Imputed values

Power generation

The imputed values for power generation have been computed at the following points covering the states where gas use is considered feasible. West Bengal, Bihar and Orissa have been left out as they are coal bearing states; Himachal Pradesh and Jammu and Kashmir have not been considered as they are too remote. The locations selected are places where power projects are proposed to be set up.

Table 13.3.1 Locations for imputed values in power generation

State	Location
Delhi	Bawana
Haryana	Fandabad, Hisar
Punjab	Doraha, Bathinda, Govindwal
Rajasthan	Dholpur, Suratgarh, Anta
Gujarat	Kawas, Gandhar, Mundra, Pipavav
Uttar Pradesh	Auraiya, Unchahar, Jawaharpur, Anpara, Partapur
Madhya Pradesh	Bhander, Rosa, Sipat, Korba, Vindhyachal, Raigarh
Maharashtra	Trombay, Chandrapur
Andhra Pradesh	Vizag
Karnataka	Raichur
Tamil Nadu	Chennai
Kerala	Kayamkulam
Assam	Guwahati

Capital cost per unit of power, including interest during construction (IDC) are annuitised using the capital recovery factor which is determined by the operating life of the project and the discount/interest rates. Annual generation, determined by the plant load factor (PLF) minus the auxiliary consumption gives the net units sent out in a year. These together provide the capital cost per unit of electricity sent out which along with the O&M costs and the fuel costs per unit give the total cost of generation of a unit of electricity sent out.

Cost of coal

Supply of coal to power plant locations has been considered from Korba, Talcher and Ib valley coal fields keeping in view the future availability of coal. Coal prices have been decontrolled from January 2000. These prices are now determined by Coal India Limited (CIL). No indications from CIL are available on how the prices will move in future.

The current power grade coal price from Korba and Talcher is Rs 396/MT and Rs 351/MT respectively. Rs. 50/MT of royalty, Rs. 21 for sizing and internal transport, Rs. 3.50/MT of excise have been added to the pithead cost to arrive at the price of coal from Korba. Estimates of coal washing charges range from Rs 150-300/MT. We have taken Rs 150/MT as the long term washing charges. Transportation costs are added to arrive at the final price of domestic coal at various power plant locations. The delivered costs of domestic coal are listed in table below.

Table 13.3.2 Delivered cost of domestic coal to selected locations

Power Plant	Coalfield	State	Distance (km)	Freight (Rs/ton)	ex-Korba prices	Delivered prices (Rs/MT)	
						washed	without washing
Dholpur	Korba	Rajasthan	967	744	449.5	1344	1215
Doraha	Korba	Punjab	1439	1068	449.5	1668	1539
Fandabad	Korba	Haryana	1175	881.9	449.5	1481	1352
Hisar	Korba	Haryana	1404	1049.5	449.5	1649	1520
Auraiya	Korba	Uttar Pradesh	998	779.8	449.5	1379	1250
Bhander	Korba	Madhya Pradesh	909	705.3	449.5	1305	1176
Bhawana	Korba	Delhi	1211	919.8	449.5	1519	1390
Kawas	Korba	Gujarat	1436	1068	449.5	1668	1539
Ghandhar	Korba	Gujarat	1351	1022.8	449.5	1622	1493
Bhatunda	Korba	Punjab	1708	1213.6	449.5	1813	1684
Suratgarh	Korba	Rajasthan	1858	1287.5	449.5	1887	1758
Anta	Korba	Rajasthan	991	761.1	449.5	1361	1232
Unchahar	Korba	Uttar Pradesh	821	629.4	449.5	1229	1100
Rosa	Korba	Madhya Pradesh	1269	957.8	449.5	1557	1428
Sipat	Korba	Madhya Pradesh	78	103.8	449.5	703	574
Korba	Korba	Madhya Pradesh	0	0	449.5	600	471
Jawaharpur	Korba	Uttar Pradesh	1030	799.6	449.5	1399	1270
Partapur	Korba	Uttar Pradesh	1687	1196.1	449.5	1796	1667
Mundra	Korba	Gujarat	1428	1068	449.5	1668	1539
Pipavav	Korba	Gujarat	1787	1246.1	449.5	1846	1717
Vindhyachal	Korba	Madhya Pradesh	768	587	449.5	1187	1058
Raigarh	Korba	Madhya Pradesh	126	128.1	449.5	728	599
Govindwal	Korba	Punjab	1496	1096.1	449.5	1696	1567
Anpara	Korba	Uttar Pradesh	648	501.6	449.5	1101	972
Raichur	Talcher	Karnataka	rail-sea-rail	1392.9	404.5	1947	1818

Power Plant	Coalfield	State	Distance (km)	Freight (Rs/ton)	ex-Korba prices	Delivered prices (Rs/MT)	
						washed	without washing
Chennai	Talcher	Tamil Nadu	rail-sea-rail	852.3	404.5	1407	1278
Vizag	Talcher	Andhra Pradesh	rail	486.6	404.5	1041	912
Trombay	Korba	Maharashtra	1248	939.4	449.5	1539	1410
Chandrapur	Korba	Maharashtra	795	610.6	449.5	1210	1081
Kayamkulam	Talcher	Kerala	rail-sea-rail	1447.3	404.5	2002	1873

Technical and financial parameters

The calorific value of domestic power grade coal is taken as 4000 kcal/kg. Power plants which are 1500 km from coal fields or beyond have to reduce the ash content to 34%. These plants have to use either washed coal or imported coal for blending. Coal washing charges are taken to be Rs 150/MT. Washing improves the calorific value of domestic coal, which increases to 4482 kcal/kg. Blending has not been considered as an option in view of the current high price of imported coal.

NTPC is planning a 660 MW supercritical coal power plant at Seepat by 2006-07. However, till date India has operated only subcritical coal based power plants. Accordingly, in this analysis only subcritical coal power plants have been considered. A typical subcritical coal based power plant has an efficiency of about 37%. The efficiency of an advanced combined cycle gas based power plant has been taken as 56%. The technical and financial parameters of subcritical coal based plants and advanced class combined cycle gas turbines are given in Tables below.

Table 13.3.3 Technical and financial parameters for subcritical coal based plants

Technical parameters	Units	Value
Plant load factor	%	75
Auxiliary consumption (indigenous coal)	%	8.0
Life of plant	Years	30
Calorific value (indigenous coal)	kcal/kg	4000
Calorific value (washed coal)	kcal/kg	4482
Heat rate per unit sent out (indigenous coal)	kcal/kWh	2526
Financial parameters		
Discount rate	%	12
Capital cost per MW (indigenous coal based)	Rs. Million	40
Fixed operation cost as % of capital cost	%	2.5
Investment period	Years	4

Table 13.3.4 Technical and financial parameters for advanced class combined cycle gas turbines

Technical parameters	Units	Value
Plant load factor	%	80
Auxiliary consumption	%	3
Life of plant	Years	30
Calorific value	Kcal/Nm ³	8500
Heat rate per unit sent out	Kcal/kWh	1583
Financial parameters		
Discount rate	%	12
Capital cost per MW	Rs. Million	30
Fixed operation cost as % of capital cost	%	2.0
Investment period	Years	3

Imputed values of gas in power generation

The imputed values at the selected power plant locations have been given in the Table below.

Table 13.3.5 Imputed values of gas in power generation

Location	Domestic coal*
Bawana	4.70
Fandabad	4.62
Hisar	4.99
Doraha	5.03
Bhatunda	5.20
Govindwal	5.09
Dholpur	4.32
Suratgarh	5.35
Anta	4.36
Kawas	5.03
Ghandhar	4.93
Mundra	5.03
Pipavav	5.26
Auraiya	4.40
Unchahar	4.07
Jawaharpur	4.44
Anpara	3.79
Partapur	5.17
Bhandar	4.23
Rosa	4.79
Sipat	2.92
Korba	2.97
Vindhyachal	3.98
Raigarh	2.97
Trombay	4.75
Chandrapur	4.03
Vizag	3.66
Raichur	5.46
Chennai	4.41
Kayamkulam	5.57
Guwahati	4.78

The calculations for the highest and lowest imputed values are at Tables 13.3.6 and 13.3. 7.

Table 13.3.6 Imputed value of gas for power generation at Sipat

Element	Unit	Gas CCGT	Domestic coal	
			washed	without washing
Capital cost	Rs.million/MW	30	40	40
PLF		80%	75%	75%
Annual output (gross)	MWh	7008	6570	6570
Auxiliary consumption	(%)	3.0%	8.0%	8.0%
Units sent out/annum (net)	MWh	6798	6044	6044
Phasing of investment				
Year -3		0	0.2	0.2
Year -2		0.2	0.3	0.3
Year -1		0.5	0.4	0.4
Year -0		0.3	0.1	0.1
Total		1	1	1
Discount factor		0.12	0.12	0.12
NPV factor		1.18	1.28	1.28
Capital cost (incld IDC)	Rs.million/MW	35.27	51.02	51.02
Life of plant	Years	30	30	30
CRF		0.12	0.12	0.12
Annuitised capital cost	Rs.million/MW	4.38	6.33	6.33
Capital cost/kWh of power	Rs./kWh	0.64	1.05	1.05
Heat rate per unit sent out	kcal/kWh	1583	2526	2526
Heat rate per unit sent out	Btu/kWh	6282	10025	10025
Fuel consumption/kWh sent out	NM ³ , kg/kWh	0.19	0.56	0.63
Fuel cost	Rs/t		703	574
Fuel calorific value	kcal/NM ³ , kcal/kg	8500	4482	4000
Fuel cost/kWh sent out	Rs/kWh		0.40	0.36
Fixed operating cost as % of capital cost	(%)	2%	2.5%	2.5%
Total fixed operating cost	Rs. million	0.600	1.000	1.000
Fixed operating cost/ kWh sent out	Rs/kWh	0.088	0.165	0.165
Capital+Fixed O&M cost/kWh sent out	Rs/kWh	0.732	1.213	1.213
Total cost per kWh sent out	Rs/kWh		1.61	1.58
Total cost per kWh sent out	\$/kWh		0.035	0.034
Imputed fuel charge	Rs/kWh		0.877	0.844
Imputed fuel charge	\$/kWh		0.019	0.018
Imputed value for gas	\$/MMBtu		3.04	2.92

Table.13.3.7 Imputed value of gas for power generation at Kayamkulam

Element	Unit	Gas CCGT	Domestic coal washed	Domestic coal without washing
Capital cost	Rs. million/MW	30	40	40
PLF		80%	75%	75%
Annual output (gross)	MWh	7008	6570	6570
Auxiliary consumption	(%)	3.0%	8.0%	8.0%
Units sent out/annum (net)	MWh	6798	6044	6044
Phasing of investment				
Year -3		0	0.2	0.2
Year -2		0.2	0.3	0.3
Year -1		0.5	0.4	0.4
Year -0		0.3	0.1	0.1
Total		1	1	1
Discount factor		0.12	0.12	0.12
NPV factor		1.18	1.28	1.28
Capital cost (incl IDC)	Rs.million/MW	35.27	51.02	51.02
Life of plant	Years	30	30	30
CRF		0.12	0.12	0.12
Annuitised capital cost	Rs.million/MW	4.38	6.33	6.33
Capital cost/kWh of power	Rs./kWh	0.64	1.05	1.05
Heat rate per unit sent out	kcal/kWh	1583	2526	2526
Heat rate per unit sent out	Btu/kWh	6282	10025	10025
Fuel consumption/kWh sent out	NM ³ , kg/kWh	0.19	0.56	0.63
Fuel cost	Rs/t		2002	1873
Fuel calorific value	kcal/NM ³ , kcal/kg	8500	4482	4000
Fuel cost/kWh sent out	Rs/kWh		1.13	1.18
Fixed operating cost as % of capital cost	(%)	2%	2.5%	2.5%
Total fixed operating cost	Rs. million	0.600	1.000	1.000
Fixed operating cost/ kWh sent out	Rs/kWh	0.088	0.165	0.165
Capital+Fixed O&M cost/kWh sent out	Rs/kWh	0.732	1.213	1.213
Total cost per kWh sent out	Rs/kWh		2.34	2.40
Total cost per kWh sent out	\$/kWh		0.051	0.052
Imputed fuel charge	Rs/kWh		1.609	1.664
Imputed fuel charge	\$/kWh		0.035	0.036
Imputed value for gas	\$/MMBtu		5.57	5.76

Urea production

Imputed values of gas in urea production have been calculated at the locations as given in the Table below. Imputed values have been estimated against imported urea. The imputed value against the urea price of Rs 7500/MT recommended by the Expenditure Reforms Commission has also been computed.

Table 13.3.8 Locations for imputed values in urea production

State	Location
Rajasthan	Kota
Uttar Pradesh	Panki, Gorakhpur, Shahjahanpur, Phulpur, Jagdishpur, Babrala
Gujarat	Hazira
Punjab	Nangal
Maharashtra	Thal
West Bengal	Durgapur
Bihar	Barauni
Andhra Pradesh	Nellore, Kakinada, Vizag
Tamil Nadu	Chennai, Tuticottin
Kerala	Kochi
Karnataka	Mangalore
Goa	Goa

Currently, there is no import duty on urea. However, imputed values have been calculated assuming a 25% import duty.

Technical and financial parameters

The technical and financial parameters of gas based urea plants as given in the Table below conform to the assumptions of the High Powered Committee on Fertilizer Pricing Policy. The capital cost of new a gas based urea plant is Rs 17,000 million and that of a new naphtha based plant is Rs. 17,500 million. The capital cost of a urea plant converting from naphtha to gas has been taken at a depreciated value of Rs 8,750 million. The technical and financial parameters of a naphtha based urea plant are listed in the Table below.

Table 13. 3.9 Technical and financial parameters of a typical gas based urea plant

Technical parameters	Unit	Value
Urea capacity	Tons/year	726,000
Energy required per ton of urea	Gcal/ton	5.40
Calorific value of gas	Kcal/Nm ³	8500
Life of plant	Years	15
Financial parameters		
Discount rate	%	12
Capital cost (new plant)	Rs. Million	17,000
Capital cost (expansion plan)	Rs. Million	15,000
Fixed operating cost	Rs/ton	854
Investment period	Years	3

Table 13.3.10 Technical and financial parameters of a typical naphtha based urea plant

Technical parameters	Unit	Value
Urea capacity	Tons/year	726,000
Energy required per ton of urea	Gcal/ton	5.10
Calorific value of gas	Kcal/Nm ³	10560
Life of plant	Years	15
Financial parameters		
Discount rate	%	12
Capital cost (new plant)	Rs. Million	17,500
Fixed operating cost	Rs/ton	924
Investment period	Years	3

Price of urea

The cif price of imported urea has fluctuated widely in the past depending critically on purchases made by India and China. The international urea prices from 1971 to 1998 are given in Table 13.2.11 in Annexure 13.2.

A cif price of \$150/MT is taken as the average. The landed cost of imported urea at the Indian port with a cif price of \$ 150/MT, an exchange rate of Rs 46 per US dollar and 25% import duty, the landed cost at the Indian port would be Rs 8625/MT.

Imputed values of gas in urea production

Expansions of gas based urea plants have been considered at ten locations: Babrala, Jagdishpur, Shahjahanpur, Gorakhpur, Hazira, Thal, Nellore, Goa, Kochi and Kakinada. The possibility of conversion of naphtha based plant to a gas based plant is taken at the following locations: Kota, Panki, Phulpur, Vizag, Kochi, Barauni, Durgapur, Manali, Mangalore, Nangal, Tuticorin and Zuarinagar.

Imputed values of gas against urea imports are given in Table 13.3.11.

Table 13.3.11 Imputed values of gas against urea imports at \$150/MT and import duty of 25%

Element	Unit	Gas based urea plant	
		New	Expansion
Urea Capacity	Tons/Year	726000	726000
Capital Cost	Rs Million	17000	15000
Phasing of investment			
Year -2		0.2	0.2
Year -1		0.5	0.5
Year -0		0.3	0.3
Total		1	1
Discount factor		0.12	0.12
NPV factor		1.18	1.18
Capital cost (incl IDC)	Rs.million	19986	17635
Life of plant	Years	15	15
CRF		0.15	0.15
Annuitised capital cost	Rs.million	2934	2589
Capital cost/Ton of urea	Rs./Ton	4042	3566
Fuel calorific value	kcal/NM ³	8500	8500
Energy required per ton of urea	Gcal/Ton	5.40	5.40
Fuel consumption/Ton of Urea	NM ³ /Ton	635	635
Fixed operating cost	Rs/Ton	854	854
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	4420
1. Babrala			
Rail distance from Kandla	kms	1284	1284

Element	Unit	Gas based urea plant	
		New	Expansion
Rail freight	Rs/T	715	715
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9340	9340
Imputed value of gas	\$/T	96.6	106.9
Imputed value of gas	\$/MMBtu	4.51	4.99
2. Jagdishpur			
Rail distance from Kandla	kms	1557	1557
Rail freight	Rs/T	850	850
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9475	9475
Imputed value of gas	\$/T	99.5	109.9
Imputed value of gas	\$/MMBtu	4.65	5.13
3. Shahjahanpur			
Rail distance from Kandla	kms	1745	1745
Rail freight	Rs/T	913	913
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9538	9538
Imputed value of gas	\$/T	100.9	111.3
Imputed value of gas	\$/MMBtu	4.71	5.19
4. Gorakhpur			
Rail distance from Kandla	kms	1711	1711
Rail freight	Rs/T	905	905
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9530	9530
Imputed value of gas	\$/T	100.7	111.1
Imputed value of gas	\$/MMBtu	4.70	5.18
5. Port locations*			
Rail distance from ports	kms	0	0
Rail freight	Rs/T	0	0
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8625	8625
Imputed value of gas	\$/T	81.1	91.4
Imputed value of gas	\$/MMBtu	3.78	4.27
6. Nangal			
Rail distance from Kandla	kms	1235	1235
Rail freight	Rs/T	696	696
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9320.7	9320.7
Imputed value of gas	\$/T	96.2	106.5
Imputed value of gas	\$/MMBtu	4.49	4.97
7. Thal			
Rail distance from Bombay	kms	0	0

Element	Unit	Gas based urea plant	
		New	Expansion
Rail freight	Rs/T	80	80
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8705.4	8705.4
Imputed value of gas	\$/T	82.8	93.2
Imputed value of gas	\$/MMBtu	3.86	4.35
8. Kota			
Rail distance from Kandla	kms	833	833
Rail freight	Rs/T	483	483
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9107.7	9107.7
Imputed value of gas	\$/T	91.6	101.9
Imputed value of gas	\$/MMBtu	4.27	4.76
9 Panki			
Rail distance from Kandla	kms	1431	1431
Rail freight	Rs/T	790	790
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9415	9415
Imputed value of gas	\$/T	98.2	108.6
Imputed value of gas	\$/MMBtu	4.58	5.07
10. Phulpur			
Rail distance from Kandla	kms	1595	1595
Rail freight	Rs/T	852	852
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	9477	9477
Imputed value of gas	\$/T	99.6	109.9
Imputed value of gas	\$/MMBtu	4.65	5.13
11. Barauni			
Rail distance from Haldia	kms	525	525
Rail freight	Rs/T	306	306
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8930.8	8930.8
Imputed value of gas	\$/T	87.7	98.1
Imputed value of gas	\$/MMBtu	4.09	4.58
12. Durgapur			
Rail distance from Haldia	kms	17	17
Rail freight	Rs/T	80	80
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8705.4	8705.4
Imputed value of gas	\$/T	82.8	93.2
Imputed value of gas	\$/MMBtu	3.86	4.35
13. Nellore			
Rail distance from Kakinada	kms	440	440

Element	Unit	Gas based urea plant	
		New	Expansion
Rail freight	Rs/T	254	254
cif price of urea	Rs/T	150	150
Delivered prices	Rs/T	8879.4	8879.4
Imputed value of gas	\$/T	86.6	96.9
Imputed value of gas	\$/MMBtu	4.04	4.52

* Port locations: Hazira, Goa, Kochi, Kakinada, Vizag, Chennai, Mangalore and Tuticorin

The Expenditure Reforms Commission has recommended that Rs 1,900/MT be allowed as concession to new units based on LNG while the farmgate price paid by the consumer is pegged at Rs 7000/ MT. In that case, the producer would receive a net price of Rs. 8,600/MT after deducting Rs 300/ MT as the marketing cost. The imputed value of gas against this producer price is \$ 4.24/MMBtu for an expansion of a gas based plant and \$4.85/MMBtu for conversion of naphtha based plant to a gas based plant. Details of imputed values against a producer price of Rs 8,600/MT are presented at Table below.

Table 13.3.12 Maximum price payable for gas if producer receives Rs 8,900/MT

Element	Unit	Gas based urea plant			Naphtha to gas based
		New	Half depreciated	Expansion	Conversion
Urea Capacity	Tons/Year	726000	726000	726000	726000
Capital Cost (new plants)	Rs Million	17000	8500	15000	8750
Phasing of investment					
Year -2		0.2	0.2	0.2	0.2
Year -1		0.5	0.5	0.5	0.5
Year -0		0.3	0.3	0.3	0.3
Total		1	1	1	1
Discount factor		0.12	0.12	0.12	0.12
NPV factor		1.18	1.18	1.18	1.18
Capital cost (incl IDC)	Rs.million	19986	9993	17635	10287
Life of plant	Years	15	8	15	8
CRF		0.15	0.20	0.15	0.21
Annuitised capital cost	Rs.million	2934	2012	2589	2156
Capital cost/Ton of urea	Rs./Ton	4042	2771	3566	2970
Fuel caloric value	kcal/NM ³	8500	8500	8500	8500
Energy required per ton of urea	Gcal/Ton	5.40	5.40	5.40	5.40
Fuel consumption/Ton of Urea	NM ³ /Ton	635	635	635	635
Fixed operating cost	Rs/Ton	854	854	854	854
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	3625	4420	3824
Price of urea received by producer	Rs/T	8600	8600	8600	8600
Maximum price payable	Rs/T	3704	4975	4180	4776
for gas/Ton of urea					
Maximum price payable for gas	\$/MMBtu	3.76	5.05	4.24	4.85

LNG vs Naphtha

Any urea producer wishing to change over to LNG would have to enter into a long-term contract (15-20 years) with LNG suppliers. In a situation of naphtha surplus in the country, the question remains if future naphtha prices could drop to such low levels as to become competitive with the LNG option. If such were the case, urea producers should stay with naphtha rather than opting for LNG. To examine such possibility, we have calculated naphtha export parity prices at three locations: Kota, Panki and Phulpur. At each location, naphtha prices have been calculated corresponding to 22 \$/bbl Middle East crude oil prices. The fob-Middle East naphtha prices have been regressed against fob-Middle East crude oil prices over March 1996 to June 2000. Transportation charges of 10\$/MT have been added to arrive at naphtha prices at Kandla port. Refinery gate prices at Mathura are obtained by deducting 46.4 \$/MT as the freight from port to refinery. Finally, naphtha export parity prices at Kota, Panki and Phulpur are arrived at by adding inland transportation. These are presented in the Table below. For comparison, naphtha import parity prices have also been evaluated and are given below. There are no customs and countervailing duty for naphtha imports in the fertilizer industry.

Table 13.3.13 Naphtha export parity prices

Parameter	Unit	Kota	Panki	Phulpur
At Crude price	\$/bbl	22	22	22
AG crude price	\$/bbl	24.2	24.2	24.2
AG naphtha price	\$/bbl	223.0	223.0	223.0
Freight: AG to Kandla	\$/T	10.0	10.0	10.0
Naphtha price at Kandla	\$/T	233.0	233.0	233.0
Freight: Kandla to Mathura	\$/T	46.4	46.4	46.4
Mathura: Refinery gate prices	\$/T	186.6	186.6	186.6
Freight	\$/T	13.6	11.7	21.1
Naphtha export parity	\$/T	200.2	198.3	207.7

Table 13.3.14 Naphtha Import Parity Price at \$22/bbl Middle East Crude Price

Element	Unit	EX-AG
Fob	\$/MT	223
Fob	Rs/MT	10258
Load Port Charges @ 1\$/MT	\$/MT	46
Freight	Rs/MT	506
Cost & freight	Rs/MT	10810
Insurance @0.3%	Rs/MT	32
Ocean Loss @ 0.3%	Rs/MT	32
Cif	Rs/MT	10875
LC Charges @ 0.3% of cif	Rs/MT	33
Landing charges @ 1% of cif	Rs/MT	109
CIF + Landing charges+ LC charges	Rs/MT	11016
Customs duty	%	0%

Element	Unit	EX-AG
Customs duty	Rs/MT	0
Cost + Basic Customs	Rs/MT	11016
CVD	%	0%
CVD	Rs/MT	0
Cost incl. Duty	Rs/MT	11016
<i>Port dues and other expenditure</i>	<i>Rs/MT</i>	<i>370</i>
Landed Cost	Rs/MT	11386
Freight		
Haldia - Panki	Rs/MT	2074
Haldia - Phulpur	Rs/MT	1785
Kandla - Kota	Rs/MT	1563
Import Parity Price		
Panki	Rs/MT	13460
Phulpur	Rs/MT	13171
Kota	Rs/MT	12949
Panki	\$/T	293
Phulpur	\$/T	286
Kota	\$/T	281

Calculation of the imputed values of gas against the above naphtha prices at Kota, Panki and Phulpur are presented in the Table below.

Table 13.3.15 Imputed values for urea production against naphtha export parity price

Element	Unit	Gas	Naphtha
		At crude price 22 \$/bbl	
Urea Capacity	Tons/Year	726000	726000
Capital Cost	Rs Million	17000	17500
Phasing of investment			
Year -2		0.2	0.2
Year -1		0.5	0.5
Year -0		0.3	0.3
Total		1	1
Discount factor		0.12	0.12
NPV factor		1.18	1.18
Capital cost (incl IDC)	Rs.million	19986	20574
Life of plant	Years	15	15
CRF		0.15	0.15
Annuitised capital cost	Rs.million	2934	3021
Capital cost/Ton of urea	Rs./Ton	4042	4161
Fuel calorific value	kcal/NM ³ , kcal/kg	8500	10560
Energy required per ton of urea	Gcal/Ton	5.40	5.10
Fuel consumption/Ton of Urea	NM ³ , kg/Ton	635	483
Fixed operating cost	Rs/Ton	854	924
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	5085
Fuel cost	Rs/t		
Kota			9207
Panki			9120
Phulpur			9552
Fuel cost/Ton of urea at	Rs/Ton		

Element	Unit	Gas	Naphtha At crude price 22 \$/bbl
Kota			4447
Panki			4404
Phulpur			4613
Total cost per ton of urea at	Rs/Ton		
Kota			9531
Panki			9489
Phulpur			9698
Imputed fuel charge at	Rs/Ton		
Kota			4636
Panki			4593
Phulpur			4802
Imputed value for gas at	\$/MMBtu		
Kota			4.70
Panki			4.66
Phulpur			4.87

Table 13.3.16 Imputed values for urea production against naphtha import parity

Element	Unit	Gas	Naphtha At crude price 22 \$/bbl
Urea Capacity	Tons/Year	726000	726000
Capital Cost	Rs Million	17000	17500
Phasing of investment			
Year -2		0.2	0.2
Year -1		0.5	0.5
Year -0		0.3	0.3
Total		1	1
Discount factor		0.12	0.12
NPV factor		1.18	1.18
Capital cost (incl IDC)	Rs.million	19986	20574
Life of plant	Years	15	15
CRF		0.15	0.15
Annuitised capital cost	Rs.million	2934	3021
Capital cost/Ton of urea	Rs /Ton	4042	4161
Fuel calorific value	Kcal/NM ³ , kcal/kg	8500	10560
Energy required per ton of urea	Gcal/Ton	5.40	5.10
Fuel consumption/Ton of Urea	NM ³ , kg/Ton	635	483
Fixed operating cost	Rs/Ton	854	924
Capital+Fixed O&M cost/Ton of Urea	Rs/Ton	4896	5085
Fuel cost at	Rs/t		
Kota			12949
Panki			13460
Phulpur			13171
Fuel cost/Ton of urea at	Rs/Ton		
Kota			6254
Panki			6500
Phulpur			6361
Total cost per ton of urea at	Rs/Ton		
Kota			11338

Element	Unit	Gas	Naphtha
			At crude price 22 \$/bbl
Panki			11585
Phulpur			11446
Imputed fuel charge at	Rs/Ton		
Kota			6443
Panki			6689
Phulpur			6550
Imputed value for gas at	\$/MMBtu		
Kota			6.54
Panki			6.79
Phulpur			6.64

Industries and captive generation

Imputed values for cement and paper industry have been calculated at the identified clusters against domestic coal.

For the glass industry, imputed values have been calculated against LPG ex-Koyali, Mathura, Mumbai and Vizag. The price of LPG has been taken at the refinery gate, the cost of movement to various locations has been omitted. For captive generation, imputed values have been calculated against naphtha ex-Koyali, Mathura, Mumbai and Vizag. Once again only the refinery gate price has been taken. If we add the transport cost of LPG and naphtha from the refinery to the actual locations, the imputed values would be larger.

Fuel costs

LPG and Naphtha

These fuels are priced on import parity basis. The 2000/01 average of fob-Middle East LPG and naphtha prices reported by Petroleum Argus have been taken. The insurance, sea freight charges, import duties and port storage and handling charges are added to the fob price to derive the landed cost of LPG and naphtha at Kandla, Mumbai and Vizag ports. The customs and countervailing duties have been taken at current rates.

Domestic coal

Average calorific value of domestic coal for industrial use is assumed to be 4,800 kcal/kg. Supplies from Korba coalfield in Madhya Pradesh have been considered. The price of D grade coal from Korba field is Rs 750/MT. Royalty of Rs 70/MT and Rs 3.50/MT of excise have been added to get the final price at Korba.

Imputed values of gas in industries and captive

Imputed values of gas for industries and captive generation have been computed on calorie equivalence. The Tables below presents calculations for the imputed values.

Table 13. 3.17 Imputed values of gas for Cement and Paper industries against domestic coal from Korba

Element	Unit	Value
<i>Imputed values of gas at Sikka</i>		
Domestic coal price	Rs /Ton	2061.9
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	3.65
Imputed value	\$/MMBtu	2.35
<i>Imputed values of gas at Kota</i>		
Element	Unit	Value
Domestic coal price	Rs /Ton	1567.5
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0003
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	2.78
Imputed value	\$/MMBtu	1.79
<i>Imputed values of gas at Delhi</i>		
Element	Unit	Value
Domestic coal price	Rs /Ton	1743.3
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	3.09
Imputed value	\$/MMBtu	1.99
<i>Imputed values of gas at Pipavav</i>		
Element	Unit	Value
Domestic coal price	Rs /Ton	2069.6
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	3.66
Imputed value	\$/MMBtu	2.36
<i>Imputed values of gas at Satna</i>		
Element	Unit	Value
Domestic coal price	Rs /Ton	1191.7
Calorific Value: Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0002
Calorific Value:LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	2.11
Imputed value	\$/MMBtu	1.36
<i>Imputed values of gas at Surat</i>		
Element	Unit	Value
Domestic coal price	Rs /Ton	1891.5
Calorific Value: Domestic coal	Kcal/Kg	4800

Element	Unit	Value
Coal price	Rs/Kcal	0.0004
Caloric Value LNG	Kcal/m ³	8500
Equivalent gas price	Rs/m ³	3.35
Imputed value	\$/MMBtu	2.16

Imputed values of gas at Amritsar

Element	Unit	Value
Domestic coal price	Rs /Ton	1962.9
Caloric Value, Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Caloric Value LNG	Kcal/m ³	8500
Equivalent gas price	Rs/m ³	3.48
Imputed value	\$/MMBtu	2.24

Imputed values of gas at Chandrapur

Element	Unit	Value
Domestic coal price	Rs /Ton	1434.1
Caloric Value, Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0003
Caloric Value LNG	Kcal/m ³	8500
Equivalent gas price	Rs/m ³	2.54
Imputed value	\$/MMBtu	1.64

Imputed values of gas at Tadpatri

Element	Unit	Value
Domestic coal price	Rs /Ton	1919.6
Caloric Value, Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Caloric Value LNG	Kcal/m ³	8500
Equivalent gas price	Rs/m ³	3.40
Imputed value	\$/MMBtu	2.19

Imputed values of gas at Malkhed

Element	Unit	Value
Domestic coal price	Rs /Ton	1762.9
Caloric Value, Domestic coal	Kcal/Kg	4800
Coal price	Rs/Kcal	0.0004
Caloric Value LNG	Kcal/m ³	8500
Equivalent gas price	Rs/m ³	3.12
Imputed value	\$/MMBtu	2.01

Table 13.3.18 Imputed values of gas for glass industries against LPG

Element	Unit	Value
Ex-Koyali prices		
LPG price	Rs /Ton	20829
Calorific Value: LPG	Kcal/Kg	11300
LPG price	Rs/Kcal	0.0018
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	15.67
Imputed value	\$/MMBtu	10.10
Ex-Mathura prices		
Element	Unit	Value
LPG price	Rs /Ton	21781
Calorific Value: LPG	Kcal/Kg	11300
LPG price	Rs/Kcal	0.0019
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	16.38
Imputed value	\$/MMBtu	10.56
Ex-Mumbai prices		
Element	Unit	Value
LPG price	Rs /Ton	20477
Calorific Value: LPG	Kcal/Kg	11300
LPG price	Rs/Kcal	0.0018
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	15.40
Imputed value	\$/MMBtu	9.93
Ex-Vizag prices		
Element	Unit	Value
LPG price	Rs /Ton	20210
Calorific Value: LPG	Kcal/Kg	11300
LPG price	Rs/Kcal	0.0018
Calorific Value: LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	15.20
Imputed value	\$/MMBtu	9.80

Annexure 13.3.19 Imputed values of gas for captive generation against naphtha

Element	Unit	Value
<i>Ex-Koyali prices</i>		
Naphtha price	Rs /Ton	14060
Calorific Value naphtha	Kcal/Kg	10560
Naphtha price	Rs/Kcal	0.0013
Calorific Value LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	11.32
Imputed value	\$/MMBtu	7.29

<i>Ex-Mathura prices</i>		
Element	Unit	Value
Naphtha price	Rs /Ton	15212
Calorific Value naphtha	Kcal/Kg	10560
Naphtha price	Rs/Kcal	0.0014
Calorific Value LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	12.24
Imputed value	\$/MMBtu	7.89

<i>Ex-Mumbai prices</i>		
Element	Unit	Value
Naphtha price	Rs /Ton	13686
Calorific Value naphtha	Kcal/Kg	10560
Naphtha price	Rs/Kcal	0.0013
Calorific Value LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	11.02
Imputed value	\$/MMBtu	7.10

<i>Ex-Vizag prices</i>		
Element	Unit	Value
Naphtha price	Rs /Ton	13730
Calorific Value naphtha	Kcal/Kg	10560
Naphtha price	Rs/Kcal	0.0013
Calorific Value LNG	Kcal/m3	8500
Equivalent gas price	Rs/m3	11.05
Imputed value	\$/MMBtu	7.12

Industry in Gujarat is now paying a gas price of Rs 2850/thousand cubic metres which equals \$1.56/MMBtu. In addition they pay royalty of 10% (\$0.16/MMBtu) and transport charges depending on location. The domestic gas price is due for a revision and may soon exceed \$3/MMBtu. The consumers will not surrender their allocations and change to coal. Indications are that most of them would continue to use gas. The imputed values of \$1.83 - 2.39/MMBtu calculated for industrial units, therefore, underestimates the price they would be willing to pay. It is possible for cement units to reduce energy consumption from 930 kJ/kg, assumed by us in computing the imputed value, to 700 kJ/kg. There are additional benefits in terms of savings in power consumption, refractory consumption and clinker quality in changing over to gas. Cement producers should be able to pay between \$2.9–3.6 / MMBtu depending on location.

How firm are the imputed values?

- There are many uncertainties in the calculation of the imputed values which are expected to be exploited by both sides during price negotiations. The principal difference in the imputed values for power and fertilizers is likely to be over efficiencies.
- For the power sector we have adopted 56% efficiency of gas turbines. Many power producers in India are more comfortable with 52% efficiency although 56% is now being guaranteed for India. This may lead to a difference of around 30 cents / MMBtu in the imputed values.
- For gas based urea production we assume that 5.4 Gcals are required for 1 MT of urea, whereas most urea producers favour 6 Gcals / MT of urea. This leads to a reduction of 40 cents / MMBtu in the imputed value of \$4.2 / MMBtu computed by us for expansion units. There is a similar difference for units converting from naphtha to gas.

Annexure 13.4 Price profile of gas demand

Table 13.4.1 All India price profile of gas demand in 2006

Sector	State	Imputed Value (\$/MMBtu)	Gas Demand (MMCMD)	Cumulative (MMCMD)
Glass	All India	9.80	2.65	2.65
Captive	All India	7.10	10.36	13.01
Power	Kerala	5.57	4.91	17.93
Power	Karnataka	5.46	3.24	21.16
Power	Punjab	5.10	1.41	22.58
Power	Gujarat	5.06	10.56	33.13
Urea (existing)	All India	5.05	26.35	59.48
Urea conversion	All India	4.85	13.87	73.36
Power	Haryana	4.80	3.24	76.60
Power	Delhi	4.70	4.38	80.97
Power	Rajasthan	4.67	5.06	86.03
Power	Tamil Nadu	4.41	6.98	93.01
Power	Maharashtra	4.39	10.94	103.96
Power	Uttar Pradesh	4.37	6.63	110.58
Urea (expansion)	All India	4.24	0.00	110.58
Power	Goa	4.03	0.06	110.64
Power	Andhra Pradesh	3.66	10.67	121.31
Power	Madhya Pradesh	3.64	0.67	121.98
Power	Bihar	2.97	0.00	121.98
Power	Orissa	2.97	0.00	121.98
Power	West Bengal	2.97	0.05	122.03
Cement & Paper	All India (excl. East, North east, MP, Haryana, UP)	1.64	10.56	132.59
Power	North East	1.56*	2.99	135.58
Cement & Paper	East, North east, MP, Haryana, UP	1.36	1.35	136.93

* It is assumed that gas will be saleable at Rs. 2850/MCM only in the North East although the imputed value against coal is higher.

Table 13.4.2 Price profile of gas demand for Northern India for 2006

Northern region - Punjab, Haryana, Uttar Pradesh, Rajasthan, Delhi

Sector	State	Imputed Value (\$/MMBtu)	Gas Demand (MMCMD)	Cumulative (MMCMD)
Glass	Punjab	10.56	0.28	0.28
Glass	Haryana	10.56	0.19	0.47
Glass	Delhi	10.56	0.45	0.92
Glass	Uttar Pradesh	10.56	0.79	1.71
Glass	Rajasthan	10.1	0.18	1.89
Captive	Punjab	7.89	0.23	2.12
Captive	Haryana	7.89	0.44	2.57
Captive	Delhi	7.89	0.04	2.60
Captive	Uttar Pradesh	7.89	1.87	4.48
Captive	Rajasthan	7.29	0.21	4.69
Power	Punjab	5.10	1.41	6.10
Urea (existing)	Punjab	5.05	0.00	6.10
Urea (existing)	Haryana	5.05	0.00	6.10
Urea (existing)	Delhi	5.05	0.00	6.10
Urea (existing)	Uttar Pradesh	5.05	8.80	14.90
Urea (existing)	Rajasthan	5.05	1.76	16.66
Naphtha conversion	Punjab	4.85	0.81	17.47
Naphtha conversion	Haryana	4.85	0.00	17.47
Naphtha conversion	Delhi	4.85	0.00	17.47
Naphtha conversion	Rajasthan	4.85	2.40	19.88
Naphtha conversion	Uttar Pradesh	4.85	4.02	23.90
Power	Haryana	4.8	3.24	27.14
Power	Delhi	4.7	4.38	31.51
Power	Rajasthan	4.67	5.06	36.57
Power	Uttar Pradesh	4.37	6.63	43.20
Urea (expansion)	Punjab	4.24	0.00	43.20
Urea (expansion)	Haryana	4.24	0.00	43.20
Urea (expansion)	Delhi	4.24	0.00	43.20
Urea (expansion)	Rajasthan	4.24	0.00	43.20
Urea (expansion)	Uttar Pradesh	4.24	0.00	43.20
Cement & Paper	Punjab	2.24	0.65	43.85
Cement & Paper	Delhi	1.99	0.00	43.85
Cement & Paper	Rajasthan	1.79	1.55	45.40
Cement & Paper	Haryana	1.36	0.00	45.40
Cement & Paper	Uttar Pradesh	1.36	0.65	46.05

Table 13.4.3 Price profile of gas demand for Western India for 2006

Western region- Madhya Pradesh, Maharashtra, Gujarat, Goa

Sector	State	Imputed Value (\$/MMBtu)	Gas Demand (MMCMD)	Cumulative (MMCMD)
Glass	Madhya Pradesh	10.56	0.03	0.03
Glass	Gujarat	10.10	0.19	0.22
Glass	Goa	10.10	0.01	0.23
Glass	Maharashtra	9.93	0.28	0.52
Captive	Madhya Pradesh	7.89	0.13	0.64
Captive	Goa	7.29	0.08	0.72
Captive	Gujarat	7.29	4.15	4.87
Captive	Maharashtra	7.10	0.60	5.47
Power	Gujarat	5.06	10.56	16.03
Urea (existing)	Goa	5.05	0.00	16.03
Urea (existing)	Madhya Pradesh	5.05	3.22	19.25
Urea (existing)	Maharashtra	5.05	4.20	23.45
Urea (existing)	Gujarat	5.05	5.51	28.96
Naphtha conversion	Goa	4.85	0.83	29.79
Naphtha conversion	Gujarat	4.85	0.00	29.79
Naphtha conversion	Madhya Pradesh	4.85	0.00	29.79
Naphtha conversion	Maharashtra	4.85	0.00	29.79
Power	Maharashtra	4.39	10.94	40.73
Urea (expansion)	Goa	4.24	0.00	40.73
Urea (expansion)	Gujarat	4.24	0.00	40.73
Urea (expansion)	Madhya Pradesh	4.24	0.00	40.73
Urea (expansion)	Maharashtra	4.24	0.00	40.73
Power	Goa	4.03	0.06	40.79
Power	Madhya Pradesh	3.64	0.67	41.46
Cement & Paper	Gujarat	2.29	2.72	44.18
Cement & Paper	Maharashtra	1.64	1.70	45.88
Cement & Paper	Goa	1.64	0.00	45.88
Cement & Paper	Madhya Pradesh	1.36	0.00	45.88

Annexure 13.5 Proposed LNG terminals in India

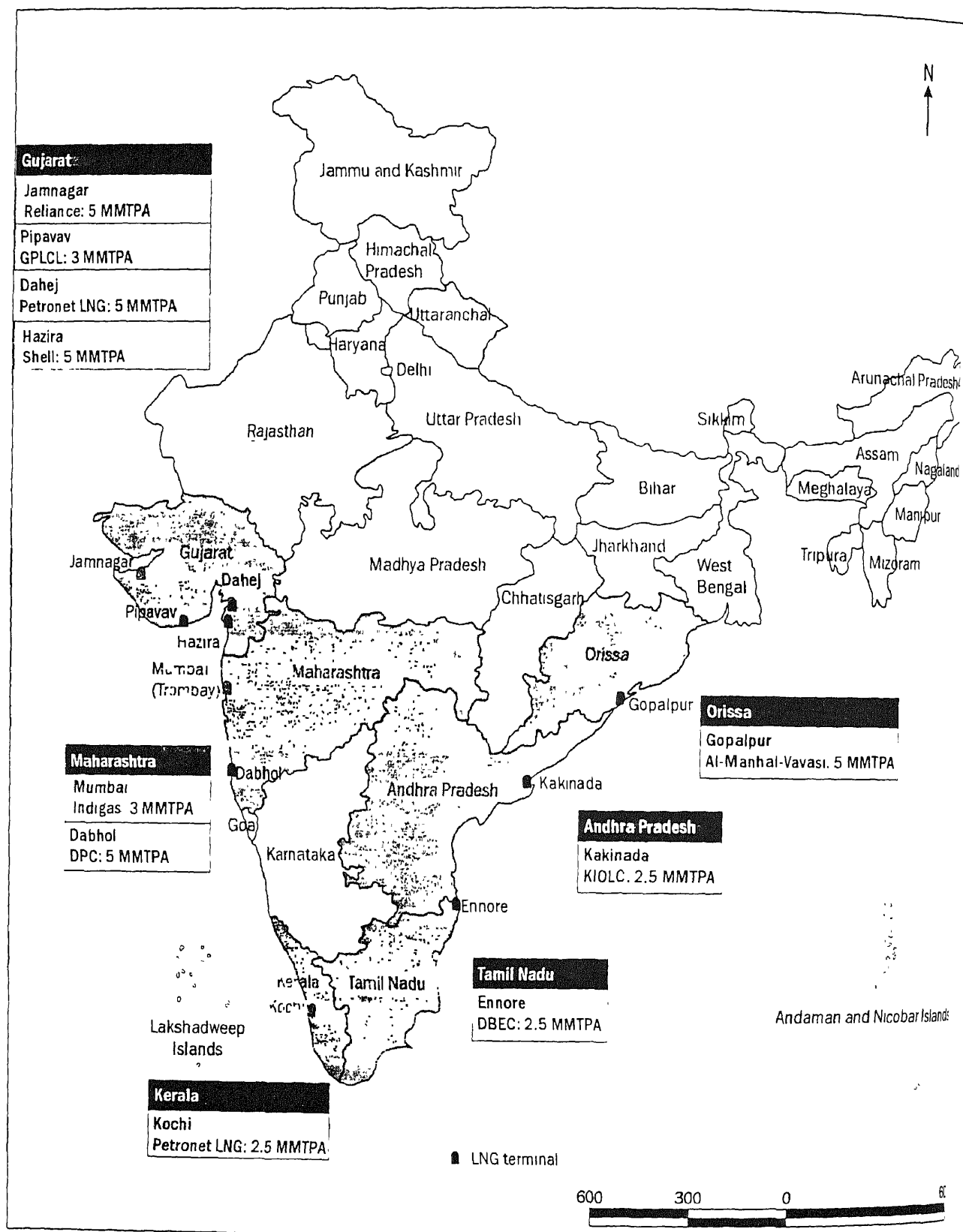
The supply sources identified by promoters of LNG import terminal proposals in India are listed in the Table below.

Table 13.5.1 Identified sources of supply to proposed LNG terminals in India

LNG terminal	Capacity (MMTPA)	Supply source	Remarks
Jamnagar	5.0	Iran	MoU signed earlier with Yemen voided
Pipavav	3.0	Under identification	
Dahej	5.0	Qatar	Balance quantity yet to be sourced
Hazira	5.0	Shell group's sources	
Trombay	3.0	Total Elf Fina sources	
Dabhol	5.0	Oman (1.7 MMTPA)	
		Abu Dhabi (0.54 MMTPA)	
Kochi	2.5	Qatar	Malaysia, a contender
Ennore	2.5	Qatar	
Kakinada	2.5	To be decided	
Gopalpur	5.0	Australia	
Total	38.5		

The locations of the ten proposals listed in Table 13.5.1 are shown in map 13.5.1. The status of these proposals is examined below.

Map. 13.5.1 Proposed LNG terminals



Jamnagar LNG terminal

The Reliance group of India has entered into a MoU with the National Iranian Oil Company (NIOC) and British Petroleum (BP) to set up a 8 MMTPA liquefaction facility for natural gas in Iran. Gas from Iran's offshore South Pars Field-Phase II is to be transported through a pipeline to Assaluyeh on the Persian Gulf where the liquefaction plant is to be put up along with LNG export facilities. This is the first MoU signed by NIOC for development of a LNG export terminal in Iran.

A joint venture company is under formation to take in hand work on the above liquefaction and export facility. The equity shareholding is likely to be NIOC-40%, Reliance-25% and BP-25%, with the remaining 10% to be allotted to a fourth partner who is yet to be selected. Terms of the JV agreement and size of the equity base of the new company are being discussed between the partners. Meanwhile, GAIL has staked its claim for equity participation in the JV to be formed. Reliance is expected to get marketing rights for 5 to 6 MMTPA of LNG. BP will, in that case, draw the remaining 2 to 3 MMTPA of LNG for marketing themselves. It is understood that feasibility studies for the liquefaction plant have been completed and the target is to have it commissioned by 2007.

For despatch of petroleum products by ocean going tankers, the 27 MMTPA Reliance refinery at Jamnagar has a jetty extending nearly 7 km into the sea with 4 berths. The draught available is suitable for receiving LNG tankers of 135,000 cu metres capacity. Reliance also has spare land available and is thus in a position to use its existing infrastructure to construct the LNG import terminal relatively quickly. The capacity of the terminal is tentatively planned at 5 MMTPA, with provision to enlarge the capacity to 10 MMPTA.

Pipavav LNG terminal

Located on the west coast of India in the state of Gujarat, Pipavav is the country's first port developed with private sector initiative, capital and management. The Gujarat Pipavav Port Limited (GPPL) which undertook the development work and is now administering and managing the port operations. The port has a natural draught of 9.5 to 11 metres, which is dredged to a depth of 12.5 metres to receive ships upto 45,000 DWT. There is a 300 metres long jetty with a separate terminal to receive LPG and liquid chemical vessels. A joint venture company promoted by GPPL and the Railways will link Pipavav by a 14 km new rail line to Rajula, and convert the 250 km Rajula – Surendranagar section from metre to broad gauge at a cost of Rs 294 crores.

The plan for the port has a provision for a separate LNG jetty and terminal next to the LPG import facilities. The Gujarat Pipavav LNG Limited (GPLNG) owned by British Gas (BG) plans to set up an LNG import terminal of 2.5 MMTPA capacity expandable to 10 MMTPA. BG plans a subsea pipeline from Pipavav to Hazira to gain access to important gas consumers in and around in Hazira, and the strategic HBJ pipeline. It would also enable BG to avail of the recently commissioned Hazira – Ankleshwar pipeline of their affiliate Gujarat Gas Company Ltd (GGCL) to further develop and enlarge gas marketing through GGCL's old infrastructure in South Gujarat.

GPLNG has signed an MoU with NTPC granting it a 26% stake in the company. NTPC agreed to source its entire gas demand of 1.6 MMTPA exclusively from GPLNG for the proposed 650 MW second stage expansion of its Kawas and Gandhar power plants. However, NTPC has recently indicated that it has not tied up LNG supplies from any source. GPLNG has invited expression of interest for the supply of 5.3 MMTPA of LNG. Eight probable suppliers have reportedly been short-listed, including Yemen LNG. The progress made by the neighbouring LNG terminal proposals at Dahej and Hazira has relegated the Pipavav proposal to the background. Pipavav's distance from the main gas consuming centres of Gujarat has added to its handicap.

Dahej LNG terminal

The Ministry of Petroleum & Natural Gas, Government of India approved the formation of a joint venture company in May, 1997 between GAIL, ONGC, IOC and BPCL to develop facilities for the import of LNG. The company was incorporated in April, 1998 under the name of Petronet LNG Ltd (PLL) with an authorised capital of Rs 1200 crores. Gas de France has joined the company as a strategic partner.

Dahej has been selected as the terminal site because of the substantial gas demand in its vicinity from existing and prospective consumers and possible access to the gas transmission infrastructure. The draught at the jetty head will be 14.5 metres. A breakwater will be constructed to withstand the severe maritime conditions during the monsoon period. The terminal capacity is to be 5 MMTPA expandable to 10 MMTPA. LNG storage will consist of $2 \times 160,000$ cubic metre tanks, with provision to add a third tank. The EPC contract for the terminal was awarded in December 2000. Foster Wheeler Energy Ltd. of the U.K. has been appointed as the project management consultants.

A long-term purchase agreement was signed by PLL in July 1999 with Rasgas of Qatar for the supply of 5 MMTPA of LNG (which can increase to 7.5 MMTPA by giving necessary notice) on fob basis. The 25 years contract effective July 2003 envisages a requirement of 5 MMTPA at Dahej and 2.5 MMTPA at Kochi but gives PLL the option to take the entire quantity of 7.5 MMTPA at Dahej. The LNG price payable by PLL will be variable and linked to the average price of a basket of crude oils.

Rasgas is reported to have agreed to give PLL a 5% stake in the 5 MMPTA LNG liquefaction - phase II plant in Qatar.

It has been decided that gas will be marketed by the following companies in the indicated proportions GAIL 60%, IOC 30%, and BPCL 10%.

The companies will use the existing pipeline transmission infrastructure of GAIL who will be exclusively responsible for gas transportation for all marketers against payment of a transportation charge. Any additional pipelines to be laid will be the responsibility of GAIL.

Hazira LNG terminal

In 1997, the Gujarat Maritime Board (GMB) on behalf of the state government of Gujarat invited applications for the development of an all weather multi-cargo port at Hazira. The initiative was to be "LNG driven", as the large requirement for natural gas in north-west India would make the Hazira port project an attractive and viable proposition. In 1999 Shell and its Indian partner Essar were awarded the rights to develop the project.

The project is a fully owned development by the Royal Dutch/Shell group. This project is being constructed on balance sheet financing and therefore no financial closure is required. Shell has floated two fully owned companies for the development of Hazira port and the LNG terminal. The Hazira Port Private Ltd. (HPPL) will provide all the facilities for a multi-cargo port at Hazira including development of a suitable approach channel, and reclamation of land from the sea. The Hazira LNG Private Ltd (HLPL) will handle installation of LNG storage tanks, receipt, regasification, transfer pipelines and send out facilities. Shell has recently obtained government approval to increase their investment from \$130 million to \$200 million.

The port will consist of a 1000 × 1200 metres basin, with a draught of 14 metres. Vessels will approach the basin through a channel dredged to a draught of 12.5 metres but capable of being eventually dredged to 17.5 metres. A breakwater 1.2 km to 1.4 km long is to be put up at a water depth of 10 to 12 metres. In its first phase, the port will accommodate LNG vessel upto 145,000

cubic metres, dry bulk vessels upto 150,000 dwt, and general dry cargo vessel upto 30,000 dwt.

The capacity of the terminal will be 5 MMTPA capable of being doubled. Two double walled cryogenic tanks of 180,000 cubic metres capacity each are to be installed initially. FIPB and CCEA clearances have been received. The Environmental Impact Assessment has been completed. Approvals have been received from the Gujarat Pollution Control Board and the CRZ administering authorities. The Ministry of Environment & Forests has accorded environmental clearance. Award of work to the selected EPC contractor is being finalized. The terminal is targeted to be commissioned in the first quarter of 2004. Shell is uniquely placed to source and ship LNG not only from the Middle East but also from south-east Asia and Australia. The precise sources of supply have not yet been disclosed.

Trombay LNG terminal

Indigas, a company owned equally by Tata Power Company, Total Gas and Power India - a wholly owned subsidiary of Total Fina Elf - and GAIL was planning a terminal at Trombay with a capacity of 3.3 MMTPA. About 1 MMTPA was to be consumed by TPC and the balance sold to local customers. As of now, it seems unlikely that the project will take off.

Dabhol LNG terminal

The terminal capacity under construction is 5 MMTPA. A full-fledged port is ready at Dabhol with a 1.8 km long jetty to receive LNG ships of 135,000 cubic metres capacity. A 2300 metres long breakwater has been provided. Three storage tanks of 160,000 cubic metres capacity each are being installed, with provision for building a fourth tank.

An Enron subsidiary called Metgas entered into an agreement with Oman-LNG in 1998 for the import of 1.26 MMTPA of LNG at Dabhol starting 2001. Later that year, Metgas signed a second agreement with Ad Gas of Abu Dhabi for a further 0.54 MMTPA of LNG. DPC's gas requirements for power generation at Dabhol was to be met from these two sources.

Metgas is also reported to have signed a confirmation of intent with Malaysia LNG Tiga for the supply of 2.6 MMTPA of LNG, starting mid-2002 for the supply of gas to consumers in Maharashtra.

The LNG terminal was to be completed by end 2001 but its commissioning is now uncertain. Several companies like GAIL and Reliance are said to be in the

race to acquire the LNG terminal but it may be some time before the negotiations are completed.

Kochi LNG terminal

The New Vypeen island situated about 4 km north-west of the Kochi Port Trust office has been selected as the site for the terminal. A 170 metres long jetty is to be built close to the terminal site. Existing draught available at the jetty head is 12 metres and will require dredging to 14.5 metres. The maritime conditions during monsoon months are not as severe as at Dahej and the tidal waves not very high. Nevertheless, 2 to 3 metres high breakwaters are to be built to the north and south of the island.

The terminal capacity is to be 2.5 MMTPA expandable to 5 MMTPA. LNG storage will consist of 2 × 110,000 cu metre tanks, with the provision to add a third tank. A detailed feasibility report of Kochi terminal had been prepared by Flour Daniel/Mitsubishi. The estimated cost of the project is around Rs 1600 crores.

PLL are working towards commissioning the terminal by the year 2005, though much remains to be done to attain this objective. In particular, it would be difficult to locate the customers for gas.

Ennore LNG terminal

The Ennore port has been notified by the Government of India as a major port under the Indian Ports Act 1908 and has been registered as a company, viz. Ennore Port Limited. Construction of the first phase of Ennore port has been funded by assistance from the Asian Development Bank and partly through investment by Chennai Port Trust and the Government of India. TIDCO has invited bids for a 2.5 MMTPA LNG terminal and 1850 MW capacity power plant to be located within the Ennore port area. The Dakshin Bharat Energy Consortium won this project. The consortium consists of 5 companies namely: Grasim Industries Limited, CMS Energy Asia, Siemens Project Venture GmbH, Germany, Unocal Bharat Ltd and Woodside Energy, Australia. The consortium has registered a new company, TN LNG and Power Co. Pvt. Ltd (TNLPC) to develop this project.

The LNG storage will consist of two 120,000 cu. metre tanks, with double walls and full containment. The terminal will be put up by TNLPC on BOO basis. The 1850 MW power plant consists of 5 units of advanced class gas turbines from Siemens, Germany operating on combined cycle mode. Construction of the power plant by TNLPC at their cost will be on BOOT basis to operate the plant

for 20 years. A firm year wise tariff has been committed for 20 years for supply of power, as per their quotation under the ICB procedure.

The Power Trading Corporation (PTC) will purchase the entire power produced under a 20-year firm Power Purchase Agreement (PPA). The Power Grid Corporation of India Ltd. (PGCIL) will, in turn, execute transmission services agreements and back-to-back PPAs with the State Electricity Boards. PTC is likely to resell power to SEBs in the southern region follows: Tamil Nadu - 750 MW, Karnataka - 300 MW, and Kerala - 200 MW with the balance quantity of 600 MW to be decided. The ability to absorb all the power to be generated will be a key factor in the materialization of this project.

The project has received FIPB approval and CCEA approval is expected shortly. TNLPC has been permitted to bring in \$426 million as foreign equity through its five share holders and a further \$656 million as foreign debt thus amounting to total foreign direct investment inflow of \$1082 million. Detailed feasibility and basic design engineering studies have been undertaken and separate EPC contractors have been identified for the power plant and LNG terminal.

During the Indian Prime Minister's visit to USA in September 2000, a Joint Development Agreement was signed by the project developers consortium, through its shareholders, with PTC signifying Government of India's commitment to the project, support by way of payment security mechanism (PSM), and interest in achieving time bound completion. The payment security mechanism, however, is not yet in place and is reportedly causing concern to the promoters. It is envisaged that financial closure would be achieved by March, 2002 so that project construction can start thereafter.

LNG is being sourced from Rasgas, Qatar. Heads of agreement have been signed and Rasgas for the LNG supply.

While 1.8 MMTPA gas will be supplied to the 1850 MW power plant, 0.7 MMTPA gas is to be sold to the Madras Chemicals and Fertilizers Ltd. and other industries and consumers through short distance pipelines by setting up a separate marketing company.

Kakinada LNG terminal

A consortium led by IOC plans to set up an LNG import terminal and a 1000 MW power plant at Kakinada port on the east coast. The Andhra Pradesh state government has issued a letter of support to the consortium. The "Kakinada Indian oil LNG consortium" comprises IOC, BP, Petronas and Cocanada Port Company Ltd. (the company operating Kakinada port at present) as partners.

The equity participation has yet to be decided though IOC is likely to take a major share. Andhra Pradesh state government may also take some equity through the Andhra Pradesh Power Generation Corporation. A detailed Project Report (DPR) of the LNG terminal prepared by Tractebel of Belgium has been submitted by KIOCL to the Andhra Pradesh government in March 2001 and comments are awaited. The capacity of the terminal will be 2.5 MMTPA initially, expandable to 10 MMTPA. The existing channel in Kakinada port is dredged to a draught of 10 metres for smaller vessels received at present. The channel can be further dredged to receive LNG ships of 135,000 cubic metre capacity. The port has enough area to construct a LNG jetty with the required turning circle. No breakwater is required. Enough open government land exists adjacent to the port boundary where a suitable plot of the required size can be provided on lease by the state government. According to the central government notification of August 2000, construction of LNG terminal facilities in the CRZ is permitted. Discussions have been held by IOC with Petronas for LNG supplies but no firm supply agreement has been reached so far. Negotiations with other LNG suppliers in the Far East are contemplated.

Gopalpur LNG terminal and integrated complex

The Al Manhal International Group (AMIG) of the United Arab Emirates, the Vavasi Oil & Gas (P) Ltd., a company of Indian technocrats, and the Industrial Promotion & Investment Corporation of Orissa Ltd have jointly proposed to set up an ambitious integrated complex at Gopalpur port on the east coast. The US \$ 6 billion plan includes an LNG import terminal, a large gas based power plant, a gas based urea-ammonia plant, a naphtha-cum-gas cracker along with a petrochemical plant and two long distance pipelines carrying natural gas to consumers in the northern and southern parts of the country. The promoters are reported to be also considering acquisition and operation of the ships required for transporting LNG to the proposed terminal at Gopalpur.

The Adani Group, which has successfully developed the Mundra port near Kandla on the west coast, has signed a MoU with Orissa state government to develop a deep water port at Gopalpur under the build-own-operate-transfer (BOOT) scheme for a concessional period of 30 years. The Adani group will be constructing solid and liquid cargo jetties after dredging and constructing breakwaters. The Gopalpur LNG Ltd (GLL) will construct and own the LNG terminal. The equity structure of the company is reported to be on the following lines AMIG & Vasavi (50%), Ipicol (5%), Australia LNG (25%), strategic partners (15%), and others (15%). The project cost is estimated at \$450 million.

The Al Manhal-Vavasi consortium has chosen Australia LNG (ALNG) as their LNG supplier. The consortium has signed a 'Heads of Agreement' followed by a 'Confirmation of Intent' with ALNG to secure 5 MMTPA of LNG for 20 years commencing from the year 2004. The Confirmation of Intent also provides an opportunity to ALNG to exercise an option for taking equity in GLL. The project is highly ambitious and it is doubtful if it will come through.

Annexures

Part-3

Annexure 14.1

Indian LPG Market

Introduction

LPG is primarily marketed by the public sector oil companies – Indian Oil Corporation (IOC), Bharat Petroleum Corporation Ltd (BPCL) and Hindustan Petroleum Corporation Ltd (HPCL). The IBP Co Ltd has commenced its LPG operations recently only. In addition, LPG imports by private parties are also allowed. LPG marketing was liberalised with the introduction of the Parallel Marketing System (PMS) in 1993, which allowed parallel marketers to import, store, bottle and market LPG. The success of parallel marketers has, however, been somewhat restricted on account of the availability of LPG at subsidised prices (domestic segment only) from the PSU (public sector units) companies.

Sales

In contrast to a decadal growth rate of 5% for consumption of all petroleum products in the country, LPG sales have recorded an average growth rate of 10.6% over the last decade. Due to constraints in availability of LPG in the past, these figures pertain more to supply volumes rather than demand.

However, of late with the commissioning new refineries and expansions of existing ones, supply constraints have been relaxed considerably. Growth in LPG sales in 2000/01 slipped below 10% for the first time since 1994/95 (Table 14.1.1). These trends reflect a saturation in the domestic LPG segment, which primarily targets the urban areas. The waiting list of 11 million customers in end of 1999 has now been liquidated with release of 12.7 million new connections in 2000/01. The government is now planning to extend the reach of LPG into rural areas. The Ministry of Petroleum & Natural Gas intends to set up 1200 new LPG distributors in the current fiscal, primarily to cater to rural needs. The public sector oil companies are also devising new strategies to meet rural requirements such as mobile LPG filling stations and smaller cylinder sizes.

Table 14.1.1 Trends in LPG consumption: TMT

Year	LPG Consumption	Growth Rate
1990/91	2415	6.5%
1991/92	2650	9.7%
1992/93	2866	8.2%
1993/94	3113	8.6%

Year	LPG Consumption	Growth Rate
1994/95	3434	10.3%
1995/96	3849	12.1%
1996/97	4267	10.9%
1997/98	4803	12.6%
1998/99	5352	11.4%
1999/00	6029	12.6%
2000/01	6610	9.6%

LPG sales can be classified into two main categories – bulk sales and bottled sales. Bulk industrial/commercial sales reflect about 10% of the total LPG consumption in the country. Bottled LPG (14.2 kg cylinder) is primarily meant for the domestic market though there are some industrial/commercial sales in 19 kg and 50 kg cylinders.

Supply

LPG availability from refineries, fractionators and imports aggregated 7001 TMT in 2000/01. After the commissioning of Reliance's 27 MMTPA refinery at Jamnagar, the need for LPG imports has reduced substantially. As against typical LPG yields of 2-4%, the LPG yield at the Jamnagar refinery is as high as 7.4% (Table 14.1.2). LPG imports consequently came down from 1587 TMT in 1999/00 to 853 TMT in 2000/01.

Of the 853 TMT of LPG imports in 2000/01, 178 TMT were imports by parallel marketers while the rest were imports by PSUs. Key players involved in parallel marketing of LPG include – SHV Energy, Shri Shakti, Caltex, Shell, Elf Gas and Mobil.

LPG production from fractionators aggregated 2050 TMT in 2000/01, with ONGC accounting for about 60% of the total production. Details of LPG production from fractionators are summarised in Table 14.1.3.

Table 14.1.2 LPG availability from refineries (TMT)

Company	Location	Capacity	Throughput	LPG Production	LPG Yield
BPCL	Mumbai	6900	8664	363	4.2%
HPCL	Mumbai	5500	5575	134	2.4%
RPL	Jamnagar	27000	25715	1901	7.4%
IOC	Koyali	12500	12004	313	2.6%
Western Region Total		51900	51959	2712	
IOC	Panipat	6000	5707	157	2.8%
IOC	Mathura	7500	7132	193	2.7%
Northern Region Total		13500	12839	350	

IOC	Barauni	4200	3123	60	1.9%
IOC	Haldia	3750	3874	53	1.4%
Eastern Region Total		7950	6996	113	
IOC	Guwahati	1000	708	14	2.0%
IOC	Digboi	650	678	2	0.4%
BRPL	Bongaigaon	2350	1490	25	1.7%
NRL	Numaligarh	3000	1451	26	1.8%
North Eastern Region Total		7000	4327	68	
CPCL	Madras	6500	6046	127	2.1%
KRL	Kochi	7500	7520	345	4.6%
CPCL	Nanmanam	500	579	18	3.1%
HPCL	Vizag	7500	6405	229	3.6%
HPCL/Birla	Mangalore	9690	6439	137	2.1%
Southern Region Total		31690	26989	856	
Total		112040	103111	4098	

Table 14.1.3 LPG production from fractionators: 2000/01 (TMT)

Fractionator	Production
ONGC	
Uran	530
Hazira	619
Ankaleshwar	12
Gandhar	54
ONGC Total	1214
GAIL	836
Total	2050

Regional demand/supply balance

On account of a concentration of refining capacity and fractionators in the western part of the country, there are acute imbalances with regards to regional demand/supply positions. The western region has a heavy surplus while the other regions of the country have deficits (Table 14.1.4).

Table 14.1.4 Regional LPG demand supply balance: 2000/01 (TMT)

Region	Demand*	Availability#	Deficit
North	2214	528	1686
West	1758	4495	-2737
East	814	270	544
South	1824	856	968
Total	6610	6148	462

* PSU sales only

Refineries & fractionators only

The western surplus, however, fails to meet the deficits in other regions and overall imports are necessitated.

Demand/supply outlook

Demand

Demand projections used in this analysis are those as per the Tenth Plan Working Group. These draw upon the work undertaken by Marketing & Development Research Associates on long-term LPG demand outlook for the country. Estimates have been worked out for domestic, industrial/commercial and automotive sectors.

Domestic demand has been separately worked out for the urban and rural sectors. While estimates for the urban sector primarily rely on data of marketing companies, rural penetration was estimated from likely trends in household incomes and a survey of intentions of non-users to switch to LPG. Households with monthly income below Rs 2,500 were not considered as potential users.

Estimates for LPG penetration in the automotive sector was again survey based. Factors taken into consideration included vehicle usage and fuel consumption as assessed from a field study. Demand estimates were derived in relation to price of Auto LPG vis-à-vis that of motor spirit.

Sectoral demand projections for the Tenth Plan period are summarised in Table 14.1.6.

Table 14.1.6 LPG demand projections (TMT)

Year	Domestic			Commercial	Industrial	Automotive	Total
	Urban	Rural	Total				
2000/01	5064	1442	6506	402	236	0	7144
2001/02	5360	1742	7102	437	255	261	8055
2002/03	5662	2052	7714	474	274	294	8756
2003/04	6023	2368	8391	513	294	329	9527
2004/05	6384	2693	9077	552	315	366	10310
2005/06	6765	3025	9790	593	336	405	11124
2006/07	7164	3364	10528	635	358	445	11966

Supply

The analysis on supply outlook takes into consideration expansions of existing refineries, commissioning of new ones and LPG production from fractionators. The Tenth plans target of refining capacity addition of 106 MMTPA seems ambitious, and this has been scaled down to 56 MMTPA for the purpose of this analysis.

Gas availability from fractionators on the other hand is expected to decline in the future. LPG supply estimates for the period under consideration are presented below in Table 14.1.7.

Table 14.1.7 LPG supply outlook (TMT)

Year	Refineries	Fractionators	Total
2001/02	4479	1950	6428
2002/03	4479	1849	6328
2003/04	4928	1838	6766
2004/05	5131	1772	6903
2005/06	6031	1735	7766
2006/07	7639	1709	9348

Demand/supply balance

A review of the demand-supply position for LPG indicates that LPG supply would remain in deficit (Table 14.1.8).

Table 14.1.8 LPG demand-supply outlook (TMT)

Year	Demand	Supply	Deficit
2001/02	8055	6428	1627
2002/03	8776	6328	2448
2003/04	9528	6766	2762
2004/05	10310	6903	3407
2005/06	11123	7766	3357
2006/07	11966	9348	2618

The deficit peaks by 2004/05 and thereafter reduces progressively as additional refining capacity becomes operational. Imports, however, would be necessary to bridge the gap between demand and supply.

Annexure 14.2

LPG demand-supply balance in the western region

Given ONGC's production facilities in the west, a more detailed examination of the western surplus is warranted. A summary of current state-wise LPG availability and bottling plant capacities in the western region is presented in Table 14.2.1.

Table 14.2.1 LPG demand-supply balance in the western region (TMT)

State	Supply Source	Availability	Bottling Plants	Demand	Surplus
Gujarat	RPL	1901	Rajkot	44	
	Hazira	619	Bhavnagar	44	
	Ankaleshwar	12	Hazira	44	
	Gandhar	54	Ankaleshwar	44	
	Gandhar (GAIL)	209	Gandhar	68	
	Koyali	313	Ahmedabad	66	
	Vaghodia	73	Gandhinagar	26	
			Hanyala	34	
Sub-Total		3181		370	2811
Maharashtra	HPC Refinery	134	Uran	132	
	BPC Refinery	363	Mumbai	122	
	Uran	530	Usar	109	
	Usar	139	Jaigaon	44	
			Aurangabad	44	
			Chandrapur	44	
			Khapn	44	
			Chakan	44	
			Pune	22	
			Manmad	34	
			Akola	44	
			Miraj	44	
			Solapur	44	
			Satara	22	
Sub-Total		1166		793	373
Madhya Pradesh	Vijaipur	406	Bhopal	88	
			Bhitoni	44	
			Manglia	34	
			Raipur	44	
			Pitampur	22	
Sub-Total		406		232	174

The maximum surplus appears in the state of Gujarat on account of the concentration of refining capacity and fractionators in the state. The real demand-supply position, however, is likely to be a bit different depending upon actual flows from supply sources to demand centres. For instance, the bulk of RPL's production is likely to be evacuated to the northern

markets via the 1.7 MMTPA Jamnagar-Loni LPG pipeline. Despite this movement, a surplus of about 1 MMT remains.

On the other hand, the surplus in Madhya Pradesh may turn out to be higher as the Raipur market is better supplied from the Vishakapatnam refinery.

Outlook for the western region

The western region accounts for about 70% of the current LPG production, while the demand in the west adds up to only 27%. A large surplus in the west, thus, follows. The demand-supply position worsens as additional refining capacity is brought on stream (Tables 14.2.2 & 14.2.3).

Table 14.2.2 Outlook on LPG availability in the west (TMT)

Supply source	Year	Availability
Existing:		
Refineries		2712
Fractionators		1783
Additional supplies:		
HPC Mumbai	2002/03	8
RPL	2003/04	444
BPC Mumbai	2004/05	214
RPL	2006/07	1257
Fractionators*	2006/07	-341
Net LPG availability	2006/07	6076

* LPG production from fractionators expected to decline in the projection period

Table 14.2.3 Projected demand-supply balance in the western region (TMT)

Year	Demand	Supply	Surplus
2001/02	2142	4394	2252
2002/03	2334	4302	1968
2003/04	2534	4734	2200
2004/05	2742	4882	2140
2005/06	2958	4845	1887
2006/07	3182	6076	2894

The surplus in the west increases from about 2.3 MMT to 2.9 MMT by the year 2006/07. The bulk of this surplus would have to be moved northwards to meet the deficits in the northern markets.

Annexure 15.1

Naphtha market overview

The following table shows the region wise sales of OMCs for the year 2000-01.

Table 15.1.1 Sector wise and region wise naphtha sales by PSUs (TMT)

	Power/Steel	Fertilizer	Petrochemical	Processors	Total
Northern	145.6	1740.9	-	66.0	1952.7
Western	1545.1	885.8	1185.8	80.5	3697.0
Southern	714.8	1199.6	1648.5	2.2	1943.9
Eastern	0.4	46.5	435.4	-	482.4
Total	2405.9	3872.8	1648.5	148.7	8076.00

Source. Industrial performance review, April 2001

The all-India sale in the year 1999-2000 was 8011.2 TMT, which meant an increase of 0.80% in the year 2000-01 over the last year. Consumer wise naphtha sales for the western region is given in Annexure 15.6.

As this table shows, the western region accounts for 45.77% of total naphtha consumption followed by northern region with 24.17% and Southern region with 24.07%. Sector wise, fertiliser accounted for 47.9% followed by Power/Steel with 29.79%. These figures, however, conceal the fact that petrochemical sector imports large quantity of naphtha since not all naphtha produced in India is petrochemical grade naphtha. If imports are also included in consumption, then petrochemical sector accounts for 42% and power/steel and fertiliser account for 33% and 25% respectively.

The imports and exports of naphtha have been as follows-

Table 15.1.2 Naphtha imports and exports (TMT)

	1996/97	1997/98	1998/99	1999/00	2000/01
Imports	15	1874	2407	1917	3165
Public Sector			168	230	340
Private Sector	15	1874	2239	1687	2825
Exports	2589	2048	720	583	2882
Net Imports	-2574	-174	1687	1334	283

Source. OCC

Naphtha imports by the private sector are undertaken mainly by Reliance Petrochemicals, Haldia Petrochemicals and Dabhol Power Company (this has now stopped). Reliance engages in swap deals where it sells its own

naphtha in return for petrochemical grade naphtha. This provides a tax benefit for it since it does not have to pay a sales tax of 24% on purchase from its own refinery. Moreover, there is a 10% duty rebate on exports.

Existing players

Presently, there are four public sector undertakings that market naphtha in the country, besides ONGC. These are the four Oil Marketing Companies (OMCs): Indian Oil Corporation (IOC) (including IBP), Bharat Petroleum Corporation Limited (BPCL) and Hindustan Petroleum Corporation Limited (HPCL). Mangalore Refineries Limited (MRL) being a joint venture refinery, sells some quantity of naphtha directly to MFL Chennai.

Company wise naphtha sales is shown below.

Table 15.1..3 Region wise, company wise and sector wise naphtha sales (TMT)

	Fertilizer				Power/Steel				Petrochemicals				Processors			
	N	W	E	S	N	W	E	S	N	W	E	S	N	W	E	S
IOC	1587.3	462.1	46.5	812.5	60	1012.1	6.4	127	639.6	418.6	14		66	68.6		2.3
BPC	153.6	17.6			82.2	133.5		342.7	546.2	16.8				10.8		
HPC		406.1		154.3	3.4	399.5					13.3			1.1		
MRL				232.8												

Source: Industrial performance review, April 2001

Note: For this table, IOC(M) and IOC(AOD) and IBP have been combined into IOC.

N: Northern Region; W: Western Region; E: Eastern Region; S: Southern Region

IOC is the dominant seller in the western region market with a market share of 59% with rest of the market equally distributed between HPCL and BPCL. However, BPCL has a bigger share than HPCL in the petrochemicals sector whereas HPCL has a bigger share than BPCL in the fertiliser and power/steel sector.

IOC, BPCL and HPCL are integrated marketing and refining companies with huge refining capacities. These companies produce over 8 million tonnes of naphtha annually and sell it either in India or export it. They produce and market many other controlled and decontrolled products. These companies also have certain hospitality arrangements among themselves, which allows them to use each other's facilities.

On the other hand, ONGC is primarily an exploration and production organisation with a handful of value added products, extracted from offshore gas and condensate. Its production is concentrated in the western region of the country though it has recently started a small primary refinery in Tatipaka, Tamil Nadu.

Sourcing of naphtha

The following table shows the production and sale of naphtha in the year 2000-01 by the three OMCs in the western region.

Table 15.1.4 Company wise production versus sales for the western region (TMT)

	HPC	BPC	KOY (IOC)	TOTAL WR
Production	603.1	1148.3	1233.8	2985.2
Sales	806.7	708.1	2182.3	3697.1
Sales - production gap	-203.6	440.2	-948.5	-711.9

As this table shows, except BPC, all the other two public sector companies sell more naphtha than their own production. HPC & IOC source naphtha either from ONGC or from refineries outside the region.

In the period May 2000 to February 2001, ONGC exported 300 TMT of naphtha, mainly to Japan out of the total production of 1664 TMT. Thus, OMCs sold around 1364 TMT of naphtha in the domestic market. And given the fact that western region was in deficit, this naphtha was sold primarily in the western region. But since the production of naphtha by ONGC was larger than the deficit in the western region, some its naphtha was sold to consumers outside the region like Chambal Fertilisers and Mangalore Chemicals and Fertilisers Limited.

Annexure 15.2

Naphtha demand supply scenario

Demand projections

The naphtha demand projections have been estimated taking into account the fact that petrochemical industry imports large quantity of naphtha due to quality differences. In the following analyses, the demand for naphtha originating from imports has been excluded for the same reason. Since ONGC's production is concentrated in the Western region, the demand estimates will be given separately for Western region also.

Projections for the petrochemical sector

The petrochemical sector has been growing at an impressive rate of 14% per annum in the last decade. Based on these growth rates and the number of proposals for setting up the petrochemical plants, the Chemical Manufacturer's Association estimates that that petrochemical industry will continue to grow at 5% per annum for the next decade. This then gives us the naphtha demand originating from the petrochemical sector, excluding imports.

Table 15.2.1 Projected naphtha demand from the petrochemical sector (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Demand	1887	1981	2080	2184	2293	2408

In the western region, a number of new projects have been cleared by the government like Reliance's Jamnagar expansion and IPCL expansion.

Table 15.2.2 Projected naphtha demand by the petrochemical sector for Western region (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	1330	1396	1466	1539	1616	1697

Projections for the power sector

According to the liquid fuel policy announced by government of India in 1997, about 12000 MW capacity was to be installed on naphtha. However, so far only 2000 MW has been set up. This is due to the high prices of naphtha that has raised the cost of generation. Due to high costs, many naphtha based power generators will shift to gas as and when gas becomes available. These are shown below.

Table 15.2.3 LNG for power plants

Power plant	Current naphtha off take	Source of LNG	Expected year of shift
Essar power	39 TMT	Petronet Dahej	2005
NTPC Kayamkulam	342 TMT	Petronet Cochin	Uncertain
APGPCL	89 TMT	Local gas	2004
BSES	36 TMT	Local gas	2004
Dabhol	577 TMT	Dabhol	2003
LANCO	157 TMT	Local gas	2001

Source, TERI estimates

Because of this shift, demand for naphtha from the power sector will be declining over the years as shown below.

Table 15.2.4 Projected demand of naphtha by power sector (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Power/Steel	2250	2250	1673	1548	1509	1509

In the western region, power plants like Essar and Dabhol will not consume any naphtha as and when gas is available to these.

Table 15.2.5 Projected demand for naphtha by power sector for Western region (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	1545	1545	968	968	929	929
Current Sales	1545	1545	1545	1545	1545	1545
Deductions	0	0	577	577	616	616
Dabhol			577	577	577	577
Essar					39	39

Projections for the fertiliser sector

For fertiliser sector also, it has been assumed that the urea plants will shift to LNG as and when it becomes available. Moreover, four existing plants – Kota, Gadepan, Kanpur and Phulpur will shift to LNG in the year 2005/6 with the coming up of Petronet's Dahej LNG terminal. The resulting naphtha demand will be as follows-

Table 15.2.6 Projected demand for naphtha by fertiliser sector (TMT)

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Fertiliser	3873	3873	3873	3873	3873	2750	1730

The fertiliser plants in the western region expected to shift to gas are KRIBHCO Hazira plant, NFL Vijaypur, IFFCO Kalol and GSFC Baroda.

Table 15.2.7 Projected demand for naphtha by fertiliser sector in Western sector (TMT)

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	886	886	886	886	886	483	483
Current Sales	886	886	886	886	886	886	886
Deletions	0	0	0	0	0	403	403
IFFCO Kalol						113	113
GSFC						60	60
NFL, Vijaypur						93	93
KRIBHCO Hazira						137	137

The total naphtha demand for the country and for the Western region is as follows-

Table 15.2.8 Naphtha demand (excluding imports) (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Total	8009	8104	7756	7915	6552	5777

Table 15.2.9 Naphtha demand from Western sector (excluding imports) (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	3761	3827	3450	3703	3028	3109

Supply projections

The current refinery capacity in India is 114 MMTPA. Tenth plan working group on Refining has outlined a number of capacity additions in the tenth plan totalling to 106 MMTPA. This seems a bit ambitious and we have accordingly scaled down the capacity addition to about 56 MMTPA based on press reports on the progress made by refineries on their capacity addition plans. The table given below shows the comparison between our estimates and tenth plan estimates for capacity addition.

Table 15.2.10 Expected capacity additions in tenth plan

Refinery	Capacity addition	Expected date of commissioning	
		Xth Plan sub-group	Our estimates
IOC, Barauni	1.8	2002/3	2002/3
IOC, Haldia	1.4	2002/3	2002/3
HPCL, Mumbai	0.33	2002/3	2002/3
CPCL, Nagapatnam	0.5	2002/3	2002/3
RPL, Jamnagar	6	2002/3	2003/4
Essar, Jamnagar	10.5	2002/3	Uncertain
IOC, Koyali	4.3	2003/4	Uncertain
IOC, Panipat	6	2003/4	Uncertain
BPCL, Mumbai	5.1	2003/4	2004/5
CPCL, Chennai	3	2003/4	2004/5
BRPL, Bongaigaon	0.35	2003/4	2003/4
IOC, Paradip	9	2003/4	2006/7
Essar, Jamnagar	1.5	2003/4	Uncertain

Refinery	Capacity addition	Expected date of commissioning	
		Xth Plan sub-group	Our estimates
NOCL, Cuddalore	6	2003/4	Uncertain
KRL, Kochi	6	2004/5	2008/9
RPL, Jamnagar	17	2005/6	2006/7
Essar, Jamnagar	12	2005/6	Uncertain
HPCL, Bhatinda	9	2005/6	2005/6
BRPL, Bongaigaon	0.3	2006/7	2006/7
BORL, Bina	6	2006/7	Uncertain
Total	106.08		

In the western region, the only capacity addition that has been taken is the BPCL Mumbai refinery's 5.1 MMTPA addition. In this region, Reliance is also expected to expand its refinery but since it is more likely to export its naphtha production, it has been excluded from the analysis.

Applying the 95% capacity utilisation factor and refinery wise naphtha yields, which are around 10%, we have the following naphtha production forecast. This forecast excludes Reliance's production in the Western region as Reliance is assumed to export all its naphtha production.

Table 15.2.11 Naphtha production forecast (TMT)

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
Production	9355	9598	9453	10291	10273	10775

For the western region, the supply projections are as follows-

Table 15.2.12 Naphtha production forecast for Western region (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	4248	4258	4066	4600	4582	4571

Naphtha demand supply gap

Taking into account the projected naphtha demand (without imports, Table 1.5) and supply, we have the following all-India projected demand supply situation.

Table 15.2.13 Naphtha demand supply gap (TMT)

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
Demand	8009	8104	7756	7915	6552	5777
Supply	9355	9598	9453	10291	10273	10775
Gap	1346	1494	1697	2376	3721	4998

As this table shows, there is a projected surplus in naphtha in the country of as much as 4.9 million tonnes in the year 2006/7.

The following table shows the region wise demand supply situation.

Table 15.2.14 Regional Naphtha demand supply gap (TMT)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07
Western Region	487	431	616	897	1554	1462
Northern Region	-674	-677	-681	-685	31	1047
Eastern Region	729	834	857	832	805	1264
Southern Region	803	907	905	1333	1331	1225
Total	1346	1494	1697	2376	3721	4998

As against the projected naphtha surplus after 2002/3, the ONGC's production in this region is as follows.

Table 15.2.15 Projected ONGC's production (TMT)

Location	Product	2002-03	2003-04	2004-05	2005-06	2006-07
URAN	Naphtha/NGL	234	243	232	220	212
Hazira	ARN	1182	739	653	654	656
	Light Naphtha	0	244	244	244	244
Ankleshwar	NGL	9	8	7	6	5
Gandhar	Naphtha	31	29	27	21	17
TOTAL		1482	1290	1189	1171	1160

Source. ONGC

It can be concluded that given the surplus situation in naphtha of about 4.4 million tonnes in the year 2006/7, ONGC's production of about 1.1 million tonnes is likely to face a tough competition from other major players in this market.

Annexure – 15.3

Calculation of landed cost of LNG at various crude prices

Table 15.3.1 Ex-Hazira price of LNG at various crude prices

<i>Elements</i>	<i>Units</i>				
Crude Price	\$/bbl	18	22	25	28
FOB LNG	\$/MMBtu	2.65	3.25	3.70	4.15
Transportation	\$/MMBtu	0.35	0.35	0.35	0.35
CIF	\$/MMBtu	3.00	3.60	4.05	4.50
Customs duty	\$/MMBtu	0.15	0.18	0.20	0.23
SADD	\$/MMBtu	0.13	0.15	0.17	0.19
Landed Cost	\$/MMBtu	3.28	3.93	4.42	4.91
Re-Gassification	\$/MMBtu	0.40	0.40	0.40	0.40
Ex-Hazira	\$/MMBtu	3.68	4.33	4.82	5.31

Imputed value calculations

Methodology

The imputed value of gas is the price of gas at which the cost of generation or production in a gas based plant equals the cost of generation/production using an alternative fuel, at a particular location. Thus it indicates the maximum price for gas at which it is competitive with the cheapest alternative fuel. The methodology used has been illustrated below.

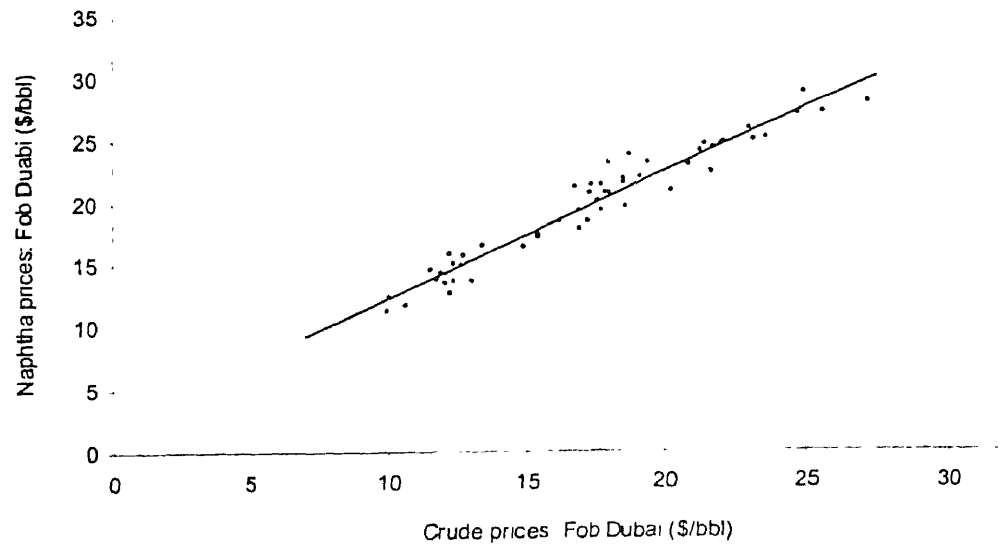
Table 15.3.2 Methodology for calculating imputed value of gas

<i>Cost of generation/production</i>	<i>Gas based</i>	<i>Competing technology</i>
Capital cost	A	c
Operation and maintenance cost	B	d
Fuel cost	X (unknown)	e
Total cost		f = c + d + e
Imputed value of gas		X = f - a - b

Annexure 15.4

Regression of naphtha prices with crude FOB AG

Figure 15.4.1



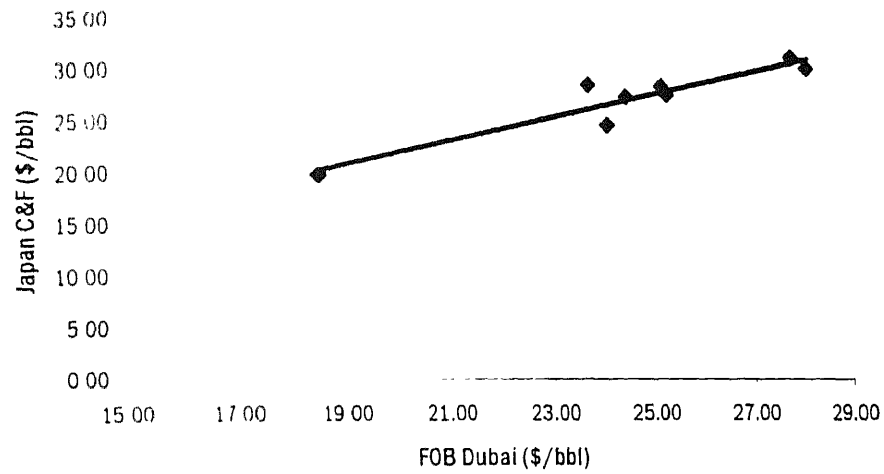
The regression equation works out to be

$$\text{Naphtha price} = 0.914 * (\text{Dubai price}) - 2.3009$$

Annexure 15.5

Regression of Japan C&F with crude FOB AG

Figure 15.5.1



The regression equation is estimated to be

$$\text{Japan C\&F} = 1.1883 * (\text{FOB crude}) - 1.6692$$

Annexure 15.6

Detailed consumer profile in the Western region

Table 15.6.1 Consumer wise naphtha sales for fertiliser sector (TMT)

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	GNFC Bharuch	0	0	0	0.1
IOC (M)	GSFC Baroda	7.6	1.2	60.5	58.7
IOC (M)	Hindustan Nitro	0	0	0	0
IOC (M)	IFFCO Kaloj	2.4	4.3	112.9	115.7
IOC (M)	NFL Vijaypur	4.5	0	93	74.9
IOC (M)	ZAC Goa	4.1	16	195.7	242.6
BPC	Deepak Fertilizer	1.1	0.3	12.2	12.1
BPC	GSFC	0	0	5.4	0
HPC	Deepak Fertilizer	0	0	0	0.9
HPC	KRIBHCO Hazira	12.2	5.6	136.5	142.7
HPC	RCF Thal	26.4	34.1	269.6	310.4
Total		58.3	61.5	885.8	958.1

Source. Industrial Performance Review, 2001

Table 15.6.2 Consumer wise naphtha sales for Petrochemical sector (TMT)

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	Indus Easter	0	0	0	0
IOC (M)	IPCL Baroda	0	0	0	0
IOC (M)	IPCL Baroda	57.2	48.7	550.5	512
IOC (M)	Nirma Limited	0.4	0.2	2.1	0.6
IOC (M)	RIL Hazira	0	16.4	4.9	77.2
IOC (M)	RIL Jamnagar	0	24.5	71.2	102.9
IOC (M)	RIL Patalganga	0	9	10.9	33.4
IOC (M)	RPL Jamnagar	0	0	0	0
BPC	HOC Rosayani	0.5	0.7	3.4	5.5
BPC	National Peroxide	0.3	0.3	4.9	4.2
BPC	NOCIL Mumbai	25	26.3	255.4	186.4
BPC	Oriental Containers	0.9	1	9.1	5.4
BPC	Rama Petrochem	0	0	0	5.7
BPC	Reliance Industries	20.1	26	273.4	272.7
HPC	HOC	0	0	0	1.6
HPC	Oswal Agro	0	0	0	0
HPC	RIL Hazira	0	0	0	0.5
Total		104.4	153.1	1185.8	1208.1

Source. Industrial Performance Review, 2001

Table 15.6.3 Consumer wise naphtha sales in power/steel sector (TMT)

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	Arvind Mills	0	0	0	6.6
IOC (M)	Birla Copper	0	0	0.7	5.8
IOC (M)	Dabhol Power	37.8	0	77.1	0.1
IOC (M)	Essar Power	0	0	38.9	232.4
IOC (M)	Essar Steel	0	42.6	126.1	278.7

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	GACL	5.7	7.7	72.4	79
IOC (M)	GIPCL	1.2	14.4	67.9	146.1
IOC (M)	GPEC (Nap)	0	35.8	214.7	296.9
IOC (M)	IPCL Dahej	22	29.4	281.5	186.2
IOC (M)	L&T Rajoula	5.9	5.4	61.8	51.8
IOC (M)	NTPC Hazira	0	0	0	0.5
IOC (M)	RSPL Goa	0	6.1	51.1	51.4
IOC (M)	Search Chem	3	0.3	19.9	41.3
BPC	Arvind Mills	3	3.6	55.2	41.5
BPC	Enron	0	0	0	8.2
BPC	Gujarat Alkali	4.9	3.6	56.7	50.5
BPC	Herdillia Chemicals	0.4	0.7	7.4	9.2
BPC	Search Chem	1.7	0	6.6	0
BPC	Vikram Ispat	0	2.7	7.6	20.9
HPC	Arvind Mills	3.8	2.1	17.8	13.9
HPC	GACL	0	0	0	5.9
HPC	Herdillia Chemicals	0	0	0.1	0
HPC	NTPC Kawas	48.2	5.9	369.2	126.9
HPC	Raymond Steel	0.4	0.2	2.8	3.6
HPC	Vikram Ispat	0	0	0	1
HPC	RSPL Goa	3.3	0	9.6	0
Total		141.3	160.5	1545.1	1658.4

Source. Industrial Performance Review, 2001.

Table 15.6.4 Consumer wise naphtha sales in Processor sector (TMT)

Supplier	Plant	Mar'01	Mar'00	2000/01	1999/00
IOC (M)	Aditya Petro	0	0.8	2.8	9.4
IOC (M)	Amit Petro	0	0.1	0	0.1
IOC (M)	Atlas Petrochem	0	0	0	4.9
IOC (M)	Avani Petro	0	0	0	15.2
IOC (M)	Bee Am Chem	0	2.7	18.5	32
IOC (M)	Bharat Petrochem	0	0	0	0.2
IOC (M)	Deepak Petro	0	0	0	0.5
IOC (M)	Gajanan Labs	0	0	3.4	0.2
IOC (M)	Gandhar Oil	0	0.9	0.9	7.4
IOC (M)	Govardhan Petro	0	0	0	11.4
IOC (M)	Hasndrup Petro	0	0	0	1.8
IOC (M)	Heera Petro	0	0.7	2.8	1.1
IOC (M)	JK Petrochem	0	0.1	2.6	0.1
IOC (M)	Jai-Hi Power Petro	0	0	0	6.9
IOC (M)	Parasnath Petro	0	1	2.5	7.2
IOC (M)	Patel Petrochem	0	0	0	7.7
IOC (M)	Poly Petro	0	0	5	0
IOC (M)	Ram remedies	0	4.7	11.6	28.8
IOC (M)	Rishi petrochem	0	0	0	4.7
IOC (M)	Silver Chem	0	1	3.5	11
IOC (M)	Sri Venkateshwara	0	1	2.6	6.8
IOC (M)	Sulakhi Chemicals	0	2.3	5.9	15
IOC (M)	Suncoats & Chem	0	0.4	4.2	10.1
IOC (M)	Vamitwala	0	0	1	0.1
IOC (M)	Venkatesh	0	0	0	5.8
IOC (M)	Yash Organics	0	0	0	5.6
IOC (M)	Others (WR)	0	0	1.2	0.1
BPC	Ankini Petro	0	0	0	7.2

BPC	Shnrang Petro	0	0.8	1.8	3.4
BPC	Others (WR)	3	1.4	9	5.7
HPC	Anant & Co	0	0.5	1.1	3.4
HPC	R S Petrochem	0	0.3	0	14
IBP	M P Petrochem	0	0	0	0.3
IBP	Maruti Petrochem	0	0	0	0.2
IBP	Panjwani Petro	0	0	0	0.3
IBP	Paschim Petro	0	0	0	13.7
IBP	Poly Petrochem	0	0	0	0.5
IBP	Shayona Petro	0	0	0	0.2
IBP	Thana Polyorganic	0	0	0	0.2
IBP	Vardan Chemicals	0	0	0.1	0.3
Total		3	18.7	80.5	243.5

Source. Industrial Performance Review, 2001.

